STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on May 14, 2009

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.
James L. Larocca

CASE 08-G-0609 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service.

ORDER ADOPTING THE TERMS OF A JOINT PROPOSAL AND IMPLEMENTING A STATE ASSESSMENT SURCHARGE

(Issued and Effective May 15, 2009)

BY THE COMMISSION:

INTRODUCTION

On May 23, 2008, Niagara Mohawk Power Corporation (Niagara Mohawk or the Company) filed to increase its natural gas delivery rates and charges by $95.3 million, including $11.1 million for an energy efficiency program.[1] The Commission suspended the proposed rates through April 20, 2009 and began this proceeding to examine the rate filing.[2] Early on, National Grid agreed to a 30-day extension of the suspension period, to May 20, 2009, to provide Department of Public Service (DPS)

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[1] Niagara Mohawk is currently doing business as National Grid. The proposed increase in delivery revenues was 33.2% or 10.9% on total revenues including natural gas charges.

[2] Case 08-G-0609, Order Suspending Major Rate Filing (issued June 18, 2008); Further Suspension of Major Rate Filing (issued October 15, 2008).

Staff additional time to audit and investigate the proposed rates.

The Commission addressed Niagara Mohawk's energy efficiency proposal by setting an interim program for the 2008-09 winter heating season.[3] Further consideration of Niagara Mohawk energy efficiency matters is being conducted in a separate proceeding coordinated with other utility company energy efficiency programs and efforts.

In October 2008, DPS Staff, and several other parties, prefiled their testimony responding to the Niagara Mohawk rate filing. In October and November 2008, public statement hearings were held in Syracuse, Schenectady and Schodack to obtain customer comments about the rate increase proposal. In December 2008, evidentiary hearings were held in Albany before Administrative Law Judge William Bouteiller.

After the hearings, National Grid and the other parties to the rate proceeding entered into settlement discussions. Notice of the settlement efforts was provided in accordance with 16 NYCRR 3.9(a)(1). The negotiations proved to be successful and the parties provided, on February 13, 2009, a Joint Proposal executed by Niagara Mohawk, DPS Staff, the United States Department of Defense, Multiple Intervenors, the Small Customer Marketer Coalition and Hess Corporation. The parties provided their statements supporting the Joint Proposal on February 27, 2009. The Joint Proposal is opposed by the Public Utility Law Project (PULP). It is concerned about the adverse impact that high natural gas delivery and commodity rates can have on low-income customers.

This Order adopts the Joint Proposal and it establishes a surcharge to collect the Temporary State Energy and Utility Service Conservation Assessment from Niagara Mohawk

[3] Case 08-G-0609, Order Adopting an Interim Energy Efficiency Program (issued September 18, 2008).

gas customers. The comments received in this case and the terms of the Joint Proposal are presented next before we provide our reasons for adopting the Joint Proposal and address the parties' support for and opposition to the proposal.

PUBLIC COMMENTS

Syracuse

The afternoon and evening hearings in Syracuse were well attended by a large group of low-income customers and their representatives. Many of them traveled great distances to address the Commission and to detail the plight of the elderly on fixed incomes, the working class, poor families and disabled individuals, among others. Speakers and members of the Monroe County Workers Benefit Council traveled from the greater Rochester area to urge the Commission to obtain utility bill debt forgiveness and service restorations for persons in poverty. The Council supports a moratorium on utility service shut-offs. Rather than see utility service rates rise, the Council seeks rate reductions for customers in financial distress. A petition was circulated and signed by over 850 persons who support the Council's position. Representatives of the Syracuse United Neighbors also attended the hearing and made points similar to those made by the Council.

Also at the Syracuse hearing, a speaker from Wyoming County suggested that New York implement a "Percentage of Income Payment Plan" similar to a program adopted in Ohio in the early 1980's. This program would limit the amount that low-income customers pay for utility service to ten percent of their monthly income. Assemblywoman Joan K. Christensen attended the hearing and described the plight of residents in the greater Syracuse area. She stated that they can ill afford higher utility rates in the prevailing economy. At the evening session, a representative of the Central New York Workers Benefit Council discussed the loss of jobs in central New York and the difficulties that customers have paying their utility bills. A county legislator also addressed customer concerns and the need to limit the amount of any rate increase.

Capital District Area

At the public statement hearing in Schenectady, the chief executive officer of the New York State Community Action Association spoke on behalf of low-income families throughout the State. She described the energy programs, heating assistance and weatherization services that non-profit organizations provide and the growing burdens that low-income customers face. She noted that minimum charges are relatively high and delivery charges can have a disproportionately large effect on a low-income family. She also stated that outstanding utility bill balances are growing due to high energy burdens and that customers in arrears are experiencing increased difficulties in obtaining assistance to have their utility service restored. The Association opposes the amount of the proposed rate increase and urges the Commission to establish manageable utility rates for low-income customers and fewer utility service shutoffs.

In Schodack, Chairman Garry A. Brown attended the public statement hearing and heard from a gentleman who suggested that Niagara Mohawk improve its customer service and billing practices, and who specifically opposed the charges that apply to the first three therms of natural gas service. The speaker also supported the public hearing process and urged the Commission to conduct additional hearings throughout the Niagara Mohawk service area. Other speakers at the hearing addressed the local economic conditions they were experiencing and urged the Commission to reject the rate increase proposal.

Correspondence, Electronic Mail and Telephone Messages

From the start of this case with Niagara Mohawk's announcement of its proposed rate increase, the Commission has received numerous letters, telephone calls and electronic messages from customers who oppose the rate increase proposal. The letters, calls and messages are similar to the statements heard from customers at the Syracuse, Schenectady and Schodack hearings.

THE JOINT PROPOSAL[4]

The Joint Proposal supports a $39.43 million rate increase beginning in May 2009.[5] It also provides for a second-stage increase in May 2010 limited to three items: property taxes; pension and other post-employment benefits; and environmental investigation and site remediation costs. Thus, the parties have presented a two-year rate plan that seeks to avoid another rate filing any time soon.

Ratemaking Provisions

Gas delivery rates are set using a capital structure derived from the capitalization of the Company's parent, National Grid plc. The rates use a 10.2% equity return allowance that includes 20 basis points ($1.59 million) as a stayout premium to recognize the risks associated with a multi-year rate plan. If the Company files for a rate increase to become effective before May 20, 2011, it will return the 20 basis points to ratepayers starting from May 20, 2009 to the date of the new rates.

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[4] This section of the Order highlights salient features of the Joint Proposal; it does not reiterate all its terms. The Joint Proposal is attached to and is part of this Order; its provisions can be read below.

[5] This amount is a 13.66% increase in delivery revenues or 5.17% in total revenues including natural gas charges. Before entering into the Joint Proposal, DPS Staff litigated and supported a $34.9 million rate increase.

If Niagara Mohawk earns over 11.35%, it will share the additional earnings with ratepayers. Between 11.35% and 13.6%, the earnings will be shared equally. Between 13.61% and 15.6%, ratepayers receive 75% and Niagara Mohawk retains 25%. Over 15.6%, ratepayers receive 90% of the earnings and the Company keeps only 10%. Niagara Mohawk will report its achieved earnings on August 31, 2010 and 2011.

The Company will implement a revenue decoupling mechanism allowing it to reconcile the delivery service revenues it achieves with the forecast amounts. Revenue-per-customer factors will be developed using the annual forecast of customers in Service Classification Nos. 1, 2 and 7. Customers will either be surcharged or they will receive refunds from the annual reconciliation.

Revenue Requirement Allocations and Rate Design

The Joint Proposal relies on an embedded cost of service study to allocate revenue requirement responsibility to the service classes. The parties jointly support a 35% allocation of distribution mains costs to the customer cost category and 65% to the demand cost component. This approach resolves a contested issue between DPS Staff, Multiple Intervenors and the U.S. Department of Defense.

The parties have also compromised their initial positions on customer charges. Rather than increase the residential customer charge to $20.00 as Niagara Mohawk proposed, the Joint Proposal supports an increase from $14.71 to $17.45. The customer charge for low-income, residential customers will decrease to $9.95. The customer charge for commercial customers in Service Classification No. 2 will increase from $19.35 to $23.65. The minimum charges include a 65 cent charge that supports the rate discount for low-income customers.

The Joint Proposal also modifies the Merchant Function Charge so as to include the uncollectible expenses associated with the monthly cost of gas; gas supply procurement costs; credit and collection costs; and the rate of return for the cost of the natural gas held in storage inventory.

Reconciliations, Deferrals and True-Ups

As of April 30, 2009, Niagara Mohawk had accumulated $46.57 million in deferrals that the Joint Proposal allows to be recovered in rates over a 38-month period, using an annual amortization rate of $14.7 million. During the two-year rate plan, Niagara Mohawk will continue to use cost reconciliations, deferral accounting and true-ups for pension and other post-employment benefits, and other items.

The Company will fully reconcile its cost of gas, and its research and development Millennium fund costs. Service Classification No. 9 (special contract) revenues will also be fully reconciled. The net margins obtained from off-system sales, capacity release credits, and the optimization of the portfolio of gas supply, transportation, storage and peaking contracts will be shared between ratepayers (85%) and the Company (15%), respectively.[6]

The Joint Proposal modifies some of the existing reconciliation, deferral and true-up mechanisms. The Company will be able to defer, during the two-year rate plan, the entire cost of any individual regulatory, legislative or accounting change whose impact exceeds $2.283 million. However, it can only defer them to the extent that its earnings do not exceed 10.2%. Cost decreases (with $2.283 million impacts) are not subject to an earnings test and they are captured entirely for ratepayers.

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[6] The sharing does not apply to capacity release credits associated with assignments made to ESCOs.

Deferral accounting and cost reconciliations continue to apply to environmental investigation and site remediation costs (and cost offsets), but they exclude the internal labor costs that Niagara Mohawk incurs. Service Classification No. 4 (commercial heat) revenues and Service Classification No. 6 (interruptible service) revenues will be reconciled, but the Company will only recover 90% of any shortage or keep 10% of any excess. Niagara Mohawk will continue to have a weather normalization adjustment; however, the existing 2.2% dead band will be eliminated.

The Joint Proposal eliminates the previous deferral, reconciliation and true-up for the gas portion of the fixed and incentive returns that apply to $209 million of pre-funded pension and other post-employment benefit costs.

The Joint Proposal introduces several new deferrals, reconciliations and true-ups. Niagara Mohawk will defer and reconcile Low-Income Program costs.[7] To the extent the Company does not spend the amount included in rates for capital expenditures, it will defer the under-spent amount.[8] Niagara Mohawk will also reconcile its interest costs, insurance premiums and remarketing fees for the NYSERDA auction rate debt it will issue.[9] The Joint Proposal also permits the Company to reconcile the cost of two new debt issuances for the natural gas operations.[10] The natural gas portion of the Company's Public

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[7] If the amount spent exceeds the amount included in rates, the Company will recover the excess only to the extent its achieved return on equity does not exceed 10.2%. Any amounts not spent below the allowance will be captured entirely and be preserved for ratepayers.

[8] Capital expenditures for coated steel services replacements and common plant are excluded.

[9] This reconciliation is subject to the mechanism described in footnote 7, above.

[10] Id.

Service Commission (PSC) assessment is also subject to full deferral and reconciliation.

The Joint Proposal permits the reconciliation and deferral of gas supply procurement costs for throughput variances only. The Company will also true up its carrying costs for gas held in storage for changes in the cost of gas and differences between the actual and forecast throughput. The late payment charges that apply to gas commodity charges will be adjusted monthly and customers will either be charged or they receive refunds for the difference between the rate allowance and the actual amounts.

To manage the build-up of deferral amounts due the Company, the Joint Proposal contains a provision that limits the carrying costs it can charge.[11] The Joint Proposal also identifies the customer services system deferral issues that remain open and pending.

Incentives

Niagara Mohawk has an existing Service Quality Assurance Program with six performance measures. The Joint Proposal doubles the minimum and maximum revenue adjustment for four of the performance measures for the natural gas operations. They increase the amount at risk by $2 million. The resulting amounts are as follows:

[11] Joint Proposal §4.5.1.

	Minimum Adjustment	Maximum Adjustment
PSC Complaint Rate	$200,000	$1,600,000
Residential Transaction Satisfaction Index	$100,000	$800,000
Small/Medium Commercial and Industrial Satisfaction Index	$100,000	$800,000
Percent of Meters Read (Unchanged)	$50,000	$400,000
Percent of Calls Answered Within 30 Seconds	$100,000	$800,000
Low-Income Customer Assistance Program Enrollment (Unchanged)	$100,000	$200,000

Before June 30, 2009, the Company will begin a collaborative process to develop monthly surveys to replace the quarterly surveys that are used to measure residential, commercial and industrial customer satisfaction. The Company will use its best efforts to complete the collaborative process by August 30, 2009.

Niagara Mohawk also has an existing Safety and Reliability Measures Program. For calendar year 2011, the following three performance levels are strengthened as follows:

Overall Damages:	3.94 per 1,000 one-call tickets
Mismarks:	0.67 per 1,000 one-call tickets
Company and Contractor Damages:	0.19 per 1,000 one-call tickets

The other Safety and Reliability Measures established in Case 06-M-0868 remain unchanged. All measures will remain in effect until the Commission acts to change them.

Low-Income Assistance Program

In addition to reducing the residential customer charge for low-income customers to $9.95, Niagara Mohawk will enhance its AffordAbility Program and increase the credit for gas customers enrolled in the arrears forgiveness program by $10 a month, bringing the credit to $30 a month. The Company will also provide a one-time $40 benefit to all elderly, blind, disabled and life support equipment customers who receive or qualify for HEAP grants.

DISCUSSION

We observe that this case was fully litigated by the active parties who participated in the evidentiary hearings in December 2008. We are also well aware of the public opposition to Niagara Mohawk’s proposal to increase natural gas delivery rates. However, the parties’ litigation positions and the public views about the proposed rate increase do not preclude the use of settlement procedures to further examine and consider the merits of the rate increase filing. We find that the settlement negotiations begun in January 2009 comply with the applicable rules. Advance notice of the meetings was given and the presiding officer determined that the persons who should have received notice were given a reasonable opportunity to participate in the settlement discussions and negotiations. As a result, the February 13, 2009 Joint Proposal is properly before us for our review.

The parties who executed and support the Joint Proposal are correct that we consider the extent to which a settlement is reached among normally adversarial parties. In this instance, almost all of the parties who participated in the rate proceeding entered into the Joint Proposal other than PULP who is opposed to its treatment of low-income customers, and the State Consumer Protection Board which neither supports or opposes this proposal. The fact that DPS Staff, Multiple Intervenors, the U.S. Department of Defense, Hess Corporation and The Small Customer Marketer Coalition have entered into the Joint Proposal provides an acceptable basis to consider the proposed terms and determine whether they satisfy the public interest and provide for the establishment of just and reasonable rates.

The parties have addressed many details that are necessary to establish proper rates. In the aggregate, they propose a natural gas delivery rate increase of $39.4 million. This is a sizable amount and it will increase residential customer bills, in most instances, by three to nine percent. Given the current state of the economy and the difficulties customers are experiencing throughout New York, we must find in these times of financial distress that the public interest is served by this increase in utility service delivery charges.

For this reason, we note that Niagara Mohawk's delivery charges have been stable and they have not increased since 1993. Over this period, the price of many other services and products increased, including natural gas commodity prices. Nevertheless, the Company avoided delivery service increases by achieving more efficient operations; by obtaining synergy savings through its merger with National Grid; and by deferring rate recovery of some cost increases that were unavoidable. In this context, it is neither surprising nor out of the ordinary for Niagara Mohawk to have presented its rate increase proposal in May 2008.

In this case, DPS Staff and other parties have fully examined and carefully audited the Company's rate filing and they have found numerous instances where the amounts requested by Niagara Mohawk could be reduced. They have also shown, in prefiled testimony and in the Joint Proposal's provisions, that much of the rate request is unavoidable and delivery rates must be increased to cover the Company's proper costs; to provide for new construction and system improvements; and to establish a reasonable return on the capital invested in the firm. We accept the results of the parties' rate case litigation and settlement efforts, and we find that the $39.43 million rate increase is proper.

Recently, we required Con Edison to implement an austerity program as the result of the circumstances related to the Company's electric operations and its recent history of rate increases.[12] We are also requiring the other large electric and gas utilities in the State to report to us their actions, since September 2008, to respond to the need for austerity.[13] Rather than consider austerity in this case, we will examine the Company's submission in Case 09-M-0435.

Beyond the Joint Proposal's ratemaking provisions, to its credit the Joint Proposal contains provisions to maintain service quality and reliability with performance incentive measures that have been adjusted for the upcoming periods. We find that the proposed minimum and maximum revenue adjustments, and updated performance levels, are proper and should be adopted.

With respect to PULP's opposition to the Joint Proposal, its concern for the well being of low-income customers--many of whom depend on public assistance and others

[12] Case 08-E-0539, Consolidated Edison Company of New York, Inc. - Electric Rates, Order Setting Electric Rates (issued April 24, 2009).

[13] Case 09-M-0435, Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs, Notice Requiring the Filing of Utility Austerity Plans (issued May 14, 2009).

who are able to make ends meet but with difficulty in these uncertain economic times--is appreciated and pertinent to this rate proceeding. We have reviewed the proposed low-income program and are satisfied that it will provide significant new benefits for low-income customers. The minimum charge reduction for designated low-income customers will ameliorate the impact of the natural gas delivery rate increase for those customers who can least afford to pay higher rates. We also note, with favor, the enhancement to the AffordAbility Program that will assist customers with amounts in arrears and the one-time benefit provided for some of the elderly and disabled customers who will benefit from them.

As to PULP’s suggestion that we should re-design rates to implement a program to substantially reduce total energy bills for public-assisted customers, we are not prepared in this proceeding to entertain any so substantial a policy change that would have major implications well beyond the scope of the natural gas delivery rates that are at issue here. The policy questions and issues PULP has raised can receive due consideration in other settings and they do not require specific action here. The rate design we are adopting does not disadvantage low-income customers on public assistance and we are satisfied that the rate design is proper for purposes of implementing the natural gas delivery rate increase that we find to be warranted.

Finally, as a technical matter, we note that Section 7.8 of the Joint Proposal addresses the possibility that the Joint Proposal could conflict with “any other document” on the same subject matter. We believe the parties here refer to the other documents that they themselves have authored or sponsored. We do not understand the provision to apply to unidentified Commission documents.

THE PARTIES' SUPPORTING STATEMENTS

The parties who support the Joint Proposal addressed the standards and criteria that the Commission has used to consider such proposals.[14] According to Niagara Mohawk, the applicable standard of review has been satisfied on the record established in this case. Together with DPS Staff, they assert that the Joint Proposal is in the public interest.

The parties state that they entered into complex, difficult and lengthy negotiations as would be expected among normally adversarial parties. They also state that the procedures they used provided all parties a reasonable opportunity to participate in the settlement efforts. Further, they believe they achieved final results that strike a proper balance that protect ratepayer interests; provide fairness to investors; and sustain the long-term viability of the utility company. They assert, as well, that the settlement results are consistent with the State's environmental, social and economic policies and they fall in the range of results that would have likely arisen from Commission action in a litigated proceeding.

Niagara Mohawk supports the Joint Proposal by pointing out that its gas delivery rates have not been increased since the 1990s. For over a decade, customers have enjoyed stability and delivery prices have remained below the level that cumulative inflation might otherwise suggest. The Company has also shown the trend in its operations since the gas delivery rates were frozen.[15] Since 2004, rate base has significantly increased due to the investments in the utility infrastructure that benefit customers. Niagara Mohawk also accumulated a large amount of regulatory deferrals for items mostly beyond its

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[14] Case 90-M-0255, Settlement Procedures, Opinion No. 92-2 (issued March 24, 1992).

[15] Niagara Mohawk's full comparison of the 2004 operations to the 2010 projections is provided in Appendix A to its February 27, 2009 Statement in Support.

control. In contrast, operation and maintenance expenses, and the overall cost of capital, decreased and offset the cost increases.

Niagara Mohawk considers the proposed second-stage increase reasonable because it is only for property taxes, pension items and environmental remediation--all items that qualify for deferral accounting. Finally, the Company points to the Joint Proposal's earnings sharing provisions and states that they ensure reasonable rates. Should earnings become significantly enhanced, customers will share in them and avoid payments for amounts that could otherwise have been deferred for future recovery.

Niagara Mohawk also lists the compromises it entered into to obtain the Joint Proposal. The Company notes that it has agreed to the capital structure supported by DPS Staff and to Staff's depreciation rates. The Company has also agreed to $2 million of synergy/efficiency savings adjustments and to exclude gas marketing program costs from rates. According to Niagara Mohawk, the overall results, including a stipulated equity return of 10.2%, are well within the range of results that could have been achieved through litigation.

Addressing revenue allocation and rate design matters, Niagara Mohawk believes that its agreements with DPS Staff, Multiple Intervenors and the U.S. Department of Defense are reasonable compromises consistent with previous Commission findings. Further, the Company considers the Joint Proposal's low-income customer assistance provisions to be a significant benefit for these customers. Finally, Niagara Mohawk supports the use of service quality, safety and reliability incentives in this multi-year rate plan.

Multiple Intervenors considers the Joint Proposal a reasonable resolution of the issues presented in this case.[16] It believes the proposal is in the public interest. From its review of the rate filing, Multiple Intervenors concludes that a sizable rate increase is unavoidable and is needed to cover a multitude of factors, including deferred costs and pension requirements. Multiple Intervenors is satisfied that all reasonable efforts were made to moderate the rate increase to the maximum extent possible, including the extension of the amortization period for the deferred costs. It is particularly interested in the revenue requirement allocations to the respective service classes and it is satisfied with the jointly proposed allocations that are keeping with Commission precedent. Multiple Intervenors also supports the Joint Proposal capital investment and incentive provisions that support system reliability, public safety and service quality.

The U.S. Department of Defense has represented the interests of federal installations and offices in the Niagara Mohawk service area, including Fort Drum. Its participation focused mostly on the allocation of distribution main costs to the respective service classes. It is satisfied with the proposed allocation of these costs between the customer and the demand components of the cost study that was used here. In the aggregate, it considers the Joint Proposal a reasonable resolution of the rate proceeding.

The Small Customer Marketer Coalition supports the Joint Proposal provisions that relate to retail access and competitive energy markets. It states that the proposal will enhance the development of a workable competitive retail market

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[16] Multiple Intervenors is an unincorporated association of about 50 industrial, commercial and institutional energy consumers with facilities located throughout New York, including Niagara Mohawk's service area.

and support the competitive economic framework for energy service companies. It specifically supports the Merchant Function Charges; the purchase of receivables and the updated discount rate; and outreach and education for retail access.

The Hess Corporation also supports the Joint Proposal for its standby sales service provisions. The revisions made to nomination deadlines and the pricing information for customers will improve the value of this service.

In support of the Joint Proposal, DPS Staff states that it is a comprehensive and balanced package that should be considered in its entirety. Staff has provided specific reasons for supporting each of the major provisions and it believes that customers will benefit from a two year rate plan. Staff supports the revenue decoupling mechanism to promote energy efficient usage.

PULP'S OPPOSITION

PULP is opposed to the Joint Proposal's treatment of low-income, residential customers.[17] It asks the Commission to adopt a more meaningful low-income rate that would reduce energy burdens for low-income customers. PULP states that the Joint Proposal does not provide sufficient reductions for low-income customers to fully alleviate their energy cost burdens.[18]

PULP presented a witness who testified in favor of a low-income customer rate about 26% below the rate that other customers pay. The witness supported automatic rate enrollment

[17] PULP's participation in this case is on its own behalf and for the New York State Community Action Association, the Albany Community Action Partnership, United Tenants of Albany and Syracuse United Neighbors.

[18] PULP also raised a holding company affiliated interest issue related to gas purchasing, portfolio management costs and off-system sales revenues that is not resolved by the Joint Proposal. This matter was withdrawn from the case and the parties' rights to address it were preserved if and when Niagara Mohawk seeks to recover these costs.

for customers who receive means-tested, social services. For customers with incomes below 50% of the Federal Poverty Line, PULP's witness advocated a 35% reduction below the standard rate. These proposals are modeled on a program in use in Massachusetts.

PULP is also opposed to the low-income surcharge being applied to and collected from low-income customers who are the beneficiaries of the programs supported by the surcharge. PULP points with favor to California where low-income customers are exempt from a similar surcharge.

PULP states that many low-income customers are at risk of losing service due to their inability to pay high energy prices. It is also concerned about Niagara Mohawk using service terminations as a tool to collect from the unemployed. According to PULP's witness, many low-income customers are unable to pay the amounts needed to heat their homes, feed their families and purchase their medical supplies. In these circumstances, PULP urges the Commission to provide bill reductions and to reduce service terminations. According to PULP, minimum charges should be reduced and volumetric charges should recover the Company's revenue requirements to avoid a regressive rate design that burdens customers. PULP criticizes the Company's minimum charges as being the practical equivalent of the "service charge" that is prohibited by Public Service Law §65(6). It believes that the minimum charge should be eliminated, or reduced, to promote energy conservation and efficiency goals.

PULP acknowledges that the Joint Proposal contains a $7.50 minimum charge discount for HEAP eligible customers; nonetheless, it considers the rate design for low-income customers a burden. It advocates for a greater discount like the one provided to customers in the KeySpan service areas on Long Island, in Brooklyn and in other states where National Grid operates. Addressing the Joint Proposal's one-time $40 bill credit for elderly, blind, disabled and life support equipment customers who receive HEAP grants, PULP believes that is does not provide sufficient relief.

PULP would support the use of an incentive mechanism to encourage the Company to reduce service terminations. There is no such device currently in place and PULP believes a collaborative process should consider a performance metric and incentive. PULP is also concerned about the Company's ability to use its revenue decoupling mechanism with service terminations to game its customer counts and obtain additional compensation.[19]

Niagara Mohawk and DPS Staff disagree with PULP's assessment of the low-income customer provisions contained in the Joint Proposal. They state that the provisions provide tangible benefits that should neither be discounted nor ignored. According to the Company, the assistance that low-income customers receive in its service area compares favorably with what customers receive in the KeySpan service areas downstate. With respect to the application of the low-income program surcharge, the Company states it is adhering to a consistent practice employed in New York. Niagara Mohawk defends the AffordAbility Program and denies that the minimum service charges constitute a "service charge". The Company is opposed to a service termination metric and performance incentive, and it insists that its Service Quality Assurance Program is sufficient and proper as it stands.

DPS Staff believes that low-income customer interests have been properly addressed by the Joint Proposal, along with

[19] In response to this assertion, Niagara Mohawk has stated that terminations for nonpayment will not affect its RDM calculations. PULP disagrees with the claim that this is a *de minimus* concern.

all other elements of the public interest. It states that the proposal is a well-balanced rate plan that is fair for the entire customer base. DPS Staff neither supports a greater minimum charge reduction for low-income customers at this time nor an exemption from the low-income program surcharge. With respect to the proper balance between minimum charges and volumetric charges, Staff states that low-income customers with high amounts of usage benefit from the lower usage charges as would any other residential customer. Staff is satisfied that low-income customers have sufficient reasons to conserve and reduce their energy consumption. Thus, Staff defends the amount of the minimum charge discount and the Joint Proposal's program for low-income customers. Staff states that it is rational, lawful, and beneficial for low-income customers and it does not overly burden the body of utility customers.

STATE ENERGY AND UTILITY SERVICE CONSERVATION ASSESSMENT

Beginning April 1, 2009, a new law required the state's public utility companies to collect and pay a Temporary State Energy and Utility Service Conservation Assessment beginning with State fiscal year 2009-10.[20] We have begun a generic proceeding to determine the best means for the utility companies to implement this assessment.[21] However, we are addressing Niagara Mohawk's circumstances here and we are authorizing it to surcharge gas customers' bills now to provide prompt implementation of the new charge in a manner that will reduce any build-up of the amount due and thereby ease its implementation and avoid a spike in customer bills. If, as a result of the generic proceeding, any changes need be made to

[20] Chapter 59 of the Laws of 2009.

[21] Case 09-M-0311, Implementation of Chapter 59 of the Laws of 2009 Establishing a Temporary Annual Assessment Pursuant to PSL §18-a(6).

the approach adopted here, we will consider such matters in Case 09-M-0311 and apply the changes prospectively.

The new assessment implemented here applies to Niagara Mohawk's gas revenues and the revenues of the energy service companies that use the Company's gas delivery service. Niagara Mohawk will estimate the energy service company gas revenues by multiplying the therms delivered for the energy service companies by the average annual commodity supply price that Niagara Mohawk charges for the sales made to its bundled customers. We believe this is an expedient and reasonable method for estimating the amount of energy service company sales revenues. Using this approach, we estimate that $756 million of energy service company revenues should be included in the revenue base for the assessment. The increased assessable revenue base and the increase of the total assessment to 2.0% (from 0.33%) results in an estimated $25.1 million of annual revenue requirements in addition to Niagara Mohawk's base delivery rates.

This amount will be collected as a surcharge to base rates. The surcharge will be allocated to each customer class on the basis of the class contribution (both delivery and supply charges) to Niagara Mohawk customers' total gas bills, including estimated energy service company supply charges. The surcharge for each class will be collected as a cents-per-therm addition to the delivery rates that the customer pays. This will keep the overall bill impact of the assessment to about 1.8%. Niagara Mohawk will be allowed to reconcile annually the amount it collects through the surcharge to the amount allowed in this Order, subject to modification in Case 09-M-0311.[22] The Company will implement the new assessment surcharge on May 20, 2009 with

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[22] This reconciliation will be allowed only to adjust amounts collected due to volumetric delivery variances from the amounts assumed in the Joint Proposal.

the new delivery rates it is allowed to collect. Starting July 1, 2009, the Company should separately state the surcharge on customers' bills.

CONCLUSION

For the reasons stated above, and from our review of the record in this case and the parties' positions concerning the Joint Proposal, we conclude that the proposed terms and provisions are in the public interest and they should be adopted.

The Commission orders:

1. The terms and provisions of the February 13, 2009 Joint Proposal attached to this order are adopted and made a part of this Order.

2. Niagara Mohawk Power Corporation is directed to file with the Commission's Secretary the tariff amendments necessary to implement the requirements of this Order on not less than one day's notice, to take effect on a temporary basis on May 20, 2009. It is also directed to take all other action necessary to implement the requirements of this Order. Any comments on the proposed tariff amendments must be received at the Commission's office within ten days of service of the tariff amendments. The amendments shall not become effective on a permanent basis until approved by the Commission.

3. The requirement of Public Service Law §66(12)(b) that newspaper publication be completed prior to the effective date of the amendments is waived, but the Company is directed to file with the Commission, not later than six weeks following the effective date of the amendments, proof that a notice of the changes set forth in the amendments and their effective date has been published for four consecutive weeks in a newspaper having general circulation in the service territory of the Company.

4. Niagara Mohawk Power Corporation is directed to cancel, by no later than May 19, 2009, the tariff amendments, statements and supplements to its Schedule P.S.C. No. 219-Gas listed in the attached Appendix.

5. Niagara Mohawk Power Corporation is authorized to surcharge customer bills to collect the difference between the new higher level of total assessment and the amount reflected in the base delivery rates consistent with the terms of this Order. The Company is required to file with the Commission’s Secretary, and serve on the parties to this proceeding, its assessment surcharge calculation amount and rate design within 20 days of the issue date of this Order. The filing shall include the estimated delivery revenues, the Company-supplied commodity prices, the energy service company commodity prices, working capital requirements and all other revenue requirement impacts.

6. This proceeding is continued.

By the Commission,

(SIGNED) JACLYN A. BRILLING
Secretary

Filing by: NIAGARA MOHAWK POWER CORPORATION D/B/A NATIONAL GRID

Amendments to Schedule P.S.C. No. 219 – Gas

Original Leaves Nos. 122.1, 122.2, 122.3, 122.4, 122.5, 122.6, 122.7, 122.8,
First Revised Leaves Nos. 88, 90, 99, 100, 102, 103, 104, 107, 108, 109, 110, 112, 113, 114, 115, 125, 127, 128, 134, 155, 156, 158, 159, 160, 163, 165, 215.2
Second Revised Leaves Nos. 2, 49, 69, 91, 92, 111, 120, 130, 142, 151, 153, 157, 164, 183, 215.1
Third Revised Leaves Nos. 3, 93, 133, 137, 145, 150, 154, 218
Fourth Revised Leaves Nos. 31, 94, 96, 98, 124, 129, 176, 185, 189
Fifth Revised Leaves Nos. 141, 180, 181, 216, 216.1
Sixth Revised Leaves Nos. 97, 184
Seventh Revised Leaf No. 178
Ninth Revised Leaf No. 179

BC Statement No. 2
MFC Statement No. 1
SBC Statement No. 1
WNA Statement No. 1
Suspension Supplements Nos. 16, 17, 18

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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Case 08-G-0609 - Proceeding on Motion	**:**
of the Commission as to the Rates, Charges,	**:**
Rules and Regulations of Niagara Mohawk	**:**
Power Corporation for Gas Service	**:**

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JOINT PROPOSAL

By And Among
Niagara Mohawk Power Corporation
d/b/a National Grid
New York State Department of Public Service Staff
United States Department of Defense
Multiple Intervenors
The Small Customer Marketer Coalition
And
Hess Corporation

Dated: February 13, 2009

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8.	Section 4.4.4 and 6.1 – Low Income Program Costs
9.	Section 4.4.5 – Under Spending of Capital Expenditures
10.	Section 4.4.6 – NYSERDA Auction Rate Debt
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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 08-G-0609 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service	:

JOINT PROPOSAL

This JOINT PROPOSAL ("Joint Proposal") is made this 13th day of February 2009, by and among Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or "Company"), New York State Department of Public Service Staff ("Staff"), United States Department of Defense, Multiple Intervenors, the Small Customer Marketer Coalition and Hess Corporation (collectively referred to herein as the "Signatory Parties").[1]

I. Procedural Context

On May 23, 2008, Niagara Mohawk filed tariff leaves and supporting testimony and exhibits for new rates and charges for gas service to be effective June 23, 2008. The new tariffs were designed to increase annual revenue recovered in base rates by $84.157 million.[2] The schedule for this case was considered at a conference held on June 26, 2008.[3] On June 18, 2008 and October 15, 2008, the Commission issued orders

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[1] Those parties included on the active parties list maintained by the Commission in this proceeding are referred to herein as "active parties."

[2] In its May 23, 2008 base rate filing, the Company also requested $11.1 million for the natural gas portion of its integrated energy efficiency programs. In its Order of September 18, 2008 approving interim energy efficiency programs in this proceeding, the Commission determined that Niagara Mohawk's permanent energy efficiency programs should be adjudicated in Case 07-M-0548.

[3] A telephone conference was subsequently held on January 9, 2009 to address a settlement track.

suspending the effective date of the Company's new rates until April 20, 2009. On July 11, 2008, the Company filed a Stipulation that it had entered with Staff that provided for a one-month extension of the suspension period without a make whole, to the effect that new rates would go into effect on May 20, 2009. On October 27, 2008, Staff, the Consumer Protection Board, Multiple Intervenors, the Public Utility Law Project and IBEW Local 97 filed their testimony addressing the Company's filing. Niagara Mohawk, Multiple Intervenors and the U.S. Department of Defense filed responsive testimony on November 17, 2008.

Evidentiary hearings were held before Administrative Law Judge William Bouteiller from December 2-5, 2008. Following the conclusion of evidentiary hearings, the parties engaged in exploratory discussions to see if settlement negotiations might be productive. On December 15, 2008, the active parties were notified of the commencement of settlement negotiations pursuant to the Commission's settlement rules at 16 NYCRR § 3.9 and a formal notice of impending settlement negotiations was filed with the Secretary. Settlement negotiations were held on December 18, 2008, December 23, 2008, December 29, 2008, January 5, 2009, January 7, 2009, January 9, 2009, January 16, 2009, January 26, 2009, February 6, 2009, February 11, 2009 and February 12, 2009. All settlement conferences were duly noticed to the active parties and held at the Company's offices in Syracuse, New York or by telephone conference.

This Joint Proposal is the product of the parties' settlement negotiations and was developed pursuant to, and in accordance with, the Commission's Settlement Procedures, as set forth in 16 NYCRR § 3.9. The Signatory Parties believe that this Joint Proposal represents a fair and reasonable resolution of the issues presented in this proceeding and should be adopted by the Commission.

II. Overall Framework

The Signatory Parties have developed a comprehensive set of terms and conditions for a two-year rate plan that applies to Niagara Mohawk's gas rates and charges for gas transportation services and Niagara Mohawk's gas operations. These terms and conditions are set forth below and in the attached Appendices. Specifically, this Joint Proposal addresses the following topics:

1. Effective Date and Term;
2. Gas Rate and Revenue Levels;
3. Computation and Disposition of Earnings;
4. Reconciliations, Deferrals and/or True-ups;
5. Additional Rate Provisions;
6. Miscellaneous Programs, Reporting Requirements and Tariff Issues; and
7. Other Provisions.

1. Effective Date and Term

The proposed Effective Date of the rate plan is May 20, 2009. Niagara Mohawk's filing in this proceeding was based upon a forecast Rate Year of the twelve months ending March 31, 2010. As a result, the revenue requirement and rate design in this Joint Proposal are based upon the agreed upon forecasts for the twelve months ending March 31, 2010. However, because the proposed Effective Date of the rate plan is May 20, 2009, the year ending May 19, 2010 is designated as "Rate Plan Year One" and the year ending May 19, 2011 is designated as "Rate Plan Year Two" in this Joint Proposal. The

"Term" of the two-year rate plan is the period beginning May 20, 2009 and ending May 19, 2011. Moreover, because most of the Company's records are kept on a monthly basis, this Joint Proposal designates an "Earnings Year," defined as the twelve months ending May 31st, for the earnings reports and earnings and certain other targets, as provided herein. For administrative reasons, several other targets and mechanisms are also on different 12-month schedules, as provided herein. Appendix N sets forth the percentage allocation of delivery revenue by month to be used in connection with any provision herein that calls for proration of annual revenue.

2. Gas Rates and Revenue Levels

2.1 Rate Plan Year One Rate and Revenue Levels

This Joint Proposal provides for a Rate Plan Year One base rate increase of $39.428 million. The components of this base rate increase are set forth in Appendix A. The revenue requirement is based on the following parameters:

(a) a Return on Equity ("ROE") of 10.2%, which, as discussed more fully below, reflects an ROE stay-out premium of 0.2% to reflect the two year Term of this Joint Proposal;

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

	% of Capital	Cost Rate	Weighted Cost Rate
Long term debt	51.10%	6.15%	3.14%
Short term debt	4.03%	1.18%	0.05%
Customer deposits	0.66%	4.85%	0.03%
Preferred stock	0.51%	3.62%	0.02%
Common Equity	43.70%	10.2%	4.46%
TOTAL	100.0%		7.70%

The overall pre-tax weighted average cost of capital is 10.69%.

(c) a rate base of $1.03 billion;

(d) the amortization in rates of previously accumulated net regulatory deferral amounts, the balance of which is projected to be $46,571,356 as of April 30, 2009, over a thirty-eight month period, which results in an annual amortization of $14,706,744 and a monthly amortization of $1,225,562, as set forth on Appendix B;

(e) annual depreciation expense of $40.847 million based on the depreciation rates set forth in Appendix C*;*

(f) a forecast of existing total delivery revenues inclusive of all miscellaneous revenues but exclusive of all commodity and gross revenue tax revenues of $280.981 million, which forecast is set forth in Appendix D; and

(g) a normalizing property tax adjustment of $2.487 million that represents a reallocation of property tax expense from the electric business to the gas business. Notwithstanding Clause 1.2.3.5 of the Merger Joint Proposal approved in Case 01-M-0075, this increased gas expense will be offset by an electric deferred credit of $2.487 million.[4]

(h) Pension and Other Post-Employment Benefit ("P&OPEB") Costs are adjusted pursuant to Exh. 144 (DAG-46), incorporated herein by reference.

2.2 Rate Plan Year One Revenue Allocation and Rate Design

2.2.1 Revenue Allocation

The allocation of the Rate Plan Year One base rate increase among Niagara Mohawk's various services is based on the following points of agreement:

(a) the allocation of incremental revenue is premised on the Company's embedded cost of service study and a classification of 35% of the cost of distribution

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4 The Company will record a monthly electric deferred credit of $207,250, with May 2009's deferral being $86,911 (*i.e.*, pro-rated for the number of days Rate Plan Year One base rates are in effect). If the Company files for new electric base rates that become effective before the end of Rate Plan Year One and if such new electric base rates reflect lower electric property taxes as a result of this reallocation, then the monthly electric deferred credit will be pro-rated for the effective date of new electric base rates and the credit will cease thereafter.

mains to the customer component and 65% to the demand component. The details of the revenue allocation and rate design are set forth in Appendix E; and

(b) $54,500 and $167,526 of the base rate increase will be allocated to Re-establishment Rates and Late Payment Charges, respectively.

2.2.2 <u>Rate Design</u>

Niagara Mohawk's existing gas rate design will change as follows:

(a) the Service Classification ("S.C.") 1 Customer Charge will be $17.45 in Rate Plan Year One, including the low income customer charge;

(b) the S.C. 2 Customer Charge will be $23.65 in Rate Plan Year One, including the low income customer charge;

(c) the Customer Charges for the S.C. 3, 4, 5, 6, 7, 8, New York State Electric and Gas Corporation and the Distributed Generation service classes will be as filed by the Company on May 23, 2008 in this proceeding, plus the low income customer charge;

(d) the cost of the low income program included in the above noted Customer Charges is further detailed in Clause 4.4.4 and in Appendix L-8 .

In addition, the S.C. 5 "single energy rate" and the S.C. 8 initial block rate will continue to be identical.

Bill impacts resulting from this rate design are shown in Appendix F.

2.2.3 <u>Merchant Function Charge</u>

Commencing with the Effective Date, the Company will recover the following costs through a Merchant Function Charge, which will be adjusted monthly.

(a) uncollectible expense for S.C.1, S.C.2, S.C.12 and S.C.13 service classifications associated with the Monthly Cost of Gas;

(b) gas supply procurement costs;

(c) credit and collection costs associated with the Monthly Cost of Gas; and

(d) the return on the cost of gas in storage inventory.

The uncollectible expense rate associated with gas costs for the S.C. 1 service classification will be determined by multiplying the S.C. 1 uncollectible rate of 2.3% by the effective Monthly Cost of Gas rate. The uncollectible expense rate associated with gas costs for S.C. 2, 12 and 13 will be determined by multiplying the non-residential uncollectible rate of 0.3% by the Monthly Cost of Gas rate. The uncollectible expense components of the Merchant Function Charge will be adjusted for actual changes in the Monthly Cost of Gas, but not for actual changes in the uncollectible rates themselves.

The amount of gas procurement costs to be reflected in the Merchant Function Charge will be as set forth in Clause 4.4.1. The rate of credit and collection costs to be reflected in the Merchant Function Charge will be as set forth in Clause 5.3.2. The amount and calculation of the return on the cost of gas in storage inventory to be reflected in the Merchant Function Charge on the Effective Date is set forth in Clause 4.4.2 and is supplemented by Appendix L-7. Each Merchant Function Charge component is net of Gross Receipts Tax.

2.2.4 <u>Lost And Unaccounted For Factor Of Adjustment</u>

Commencing with the Effective Date, the Company's allowed Lost and Unaccounted For ("LAUF") percentage will be 1.62%. The Company will not count the gas used by the Company ("Company Use") as LAUF gas, and the Company's calculation of actual LAUF to be filed each year will not include Company Use of gas.

Company Use of gas by gas operations will instead be fully recovered through the annual reconciliation of gas commodity revenues collected to the cost of gas incurred.

2.2.5 Revenue Decoupling Mechanism ("RDM")

An RDM will apply to S.C. 1, 2 and 7 and will reconcile actual delivery service revenues to allowed delivery service revenues. Actual delivery service revenues are defined as the revenue from delivery rates adjusted for the Weather Normalization Clause (see Clause 4.2.4), excluding Gross Receipts Taxes, Merchant Function Charge revenue, Net Revenue Sharing Surcharge/Credit revenue, Research and Development Surcharge revenue, Economic Development discounts, discounts and customer charges associated with the Low Income Program, and all other applicable credits and surcharges. The allowed delivery service revenues will be developed using revenue per customer[5] (RPC) factors, which are based upon the annual customer and volume forecast underlying the rates set forth in this Joint Proposal for groups: S.C. 1 heat, S.C. 1 non-heat, S.C. 2 Residential, S.C. 2 Commercial, S.C. 2 Industrial and S.C. 7.

Under the RDM, actual delivery service revenues for each annual period commencing June 1, 2009 will be reconciled by comparing actual annual delivery service revenues per group with the allowed delivery service revenues per group (the group RPC factor multiplied by the actual average number of customers in the group).[6] The Company will surcharge or refund customers if the actual delivery service revenues differ from allowed delivery service revenues. Any over or under collection at the end of the reconciliation period will include simple interest at the prevailing other customer capital

[5] A customer will be defined as an active account that is quantified at the same point in time each month. The Company has 20 bill cycles with various scheduled read dates. The Company will identify the customer count at bill cycle 19 each month.

[6] Revenue billed in June 2009 and June 2010 will be adjusted to reflect the rate changes effective May 20th as being in effect for the entire billing month.

rate issued by the Commission. The shortfall or excess will be surcharged or refunded to customers in each group on a volumetric basis over the 12 month period commencing the following January 1st. The rate per therm will be developed using a forecast level of throughput per group. All refunds or surcharges will be subject to reconciliation and included in the subsequent RDM reconciliation. Illustrative examples of the RDM are set forth in Appendix G.

Prior to March 31, 2010, the Company will conduct a review of the customer classifications of S.C. 1. That review will be based solely on a review of customer load profiles using load criteria established by the Company. The Company will provide those criteria and the results of its review to Staff and the active parties. Niagara Mohawk will implement any changes to the S.C. 1 RPC factors warranted by this review on a prospective basis and so as not to depart from the overall revenue target underlying the rates set in accordance with this Joint Proposal for Rate Plan Year One and Rate Plan Year Two. Both actual and allowed delivery revenues will be adjusted as of June 1, 2009 to reflect any reclassifications. An illustration of the method to be used is presented in Appendix G. If the parties disagree on any issue with respect to this review that cannot be resolved informally, the issue will be presented to the Commission for a final resolution.

The Company will develop a customer count proxy for each RPC group. The customer count proxy will be derived monthly by dividing the total minimum charge revenue billed during each month by the effective minimum charge for that month. At the end of the rate plan year, the resulting actual customers and proxy customers calculated for each month will be summed to obtain "actual customer months" and "proxy customer months." An example of this calculation is set forth at Appendix H. If the annual proxy customer months minus the actual annual customer months divided by the actual annual customer months is greater than 1.0%, then the Company will investigate the matter further to determine the correct number of customers. The Company will present its findings to Staff and to the active parties. If the appropriate customer count cannot be resolved informally, it will be presented to the Commission for a final resolution.

No later than 90 days after the end of each rate plan year, the Company will make an annual filing that sets forth the results of the operation of the RDM mechanism. The Company's annual filing will include an analysis that will compare (i) the Company's customer count, and (ii) the customer count proxy for each RDM group. With respect to annual filings made after the filing for Rate Plan Year One, the Company will attempt to make the filing sooner than 90 days following the end of the rate plan year and to implement the reconciliation as soon as possible thereafter.

2.3 Rate Plan Year Two Re-opener

2.3.1 Rate Adjustments To Be Effective During Rate Plan Year Two

On or before April 13, 2010, the Company will make a fully supported filing to update the following cost items, consistent with the methodology described below and as illustrated in Appendix I, for Rate Plan Year Two:

2.3.1.1 Property Taxes

The Company will begin with the total actual tax year 2009 city and school utility operating taxes and the total actual 2010 State (including Special Franchise), Town and County utility operating taxes and will escalate those taxes for Rate Plan Year Two by applying the average actual percentage increase in these taxes over the five year period 2005-2009. This escalation will apply *pro rata* to the utility operating tax expense in those months in Rate Plan Year Two that are not reflected in the actual taxes. This portion of the Company's Rate Plan Year Two re-opener filing will be provided to Staff for review no later than February 26, 2010.

2.3.1.1.1 <u>Gas Property Taxes</u>

The Rate Plan Year Two Gas Property Taxes will be 21.49% of total Niagara Mohawk operating property taxes described in Clause 2.3.1.1 above. In addition, 1.49% of those forecast total operating property taxes will be deferred as an electric deferred credit for the future benefit of the Company's electric customers. To the extent the Company's Rate Plan Year Two base rates remain in effect beyond May 19, 2011, a *pro rata* share of the second year electric deferred credit will continue to be recorded. If the Company files for new electric base rates that become effective either during or after Rate Plan Year Two, the electric monthly deferred credit will cease upon the effective date of new electric base rates if the new electric property tax allowance properly reflects the electric-to-gas property tax reallocation set forth in Clause 2.1.(g).

2.3.1.2 <u>P&OPEB Costs</u>

For the Niagara Mohawk P&OPEB plans, the actuary prepares separate costs estimates for: (a) Niagara Mohawk employees working directly for Niagara Mohawk, and (b) Niagara Mohawk employees working for the service company. The actuary also prepares separate P&OPEB cost estimates for non-Niagara Mohawk employees working for the service company.

For item (a), the Company's updated gas P&OPEB expense will be calculated as follows: (i) the total P&OPEB expense estimate, exclusive of separation and early retirement costs, as determined by the Company's actuary, for the year ending March 31, 2011; (ii) the amount in (i) will be reduced for the P&OPEB cost associated with the four additional consumer advocates; (iii) 17% of the amount in (ii) will be allocated to gas operations; and (iv) the amount in (iii) will be reduced by 31.5402% to reflect the agreed upon forecast fringe benefit capitalization percentage.

For item (b) and for the P&OPEB expenses of non-Niagara Mohawk employees working for the service company, the Company's updated gas P&OPEB expense will be calculated as follows: (i) the total P&OPEB expense estimates for such service company employees, exclusive of any separation and early retirement costs, as determined by the Company's actuary, for the year ending March 31, 2011; (ii) the forecast rate of 25.76% of the amount in (i) will be allocated to Niagara Mohawk; and, (iii) 17% of the amount in (ii) will be allocated to Niagara Mohawk gas operations.

2.3.1.3 Site Investigation And Remediation ("SIR") Costs

The Company's updated SIR costs will be based on 15% of total actual (including non-internal labor, but excluding internal labor) SIR Costs incurred in the fiscal year ending March 31, 2010.

2.3.2 Revenue Allocation And Rate Design In Rate Plan Year Two

The revenue allocation and rate design for the change in revenue in Rate Plan Year 2 will consist of a two step process. The first step will be to increase the S.C. 1 customer charge to $17.85, including the Low Income Program customer charge, and to decrease the S.C. 1 energy blocks as necessary to make the change revenue neutral. The second step will be to allocate the change in revenue for Rate Plan Year 2 determined pursuant to Clause 2.3.1 of this Joint Proposal. Such change in revenue will be allocated to S.C. 1, 2, 3, 5, 7, 8 and 12 on the same basis as the change in revenue for Rate Plan Year One is allocated, as set forth in Clause 2.2.1 of the Joint Proposal and as reflected in Appendix E, and will be applied to the energy block rates only.

2.3.3 <u>RPC Factors</u>

The Company will update the RPC factors to reflect the change in revenue in Rate Plan Year Two.

2.3.4 <u>Stay-out Premium</u>

A portion (0.2%) of the ROE underlying the revenue requirement set forth in this Joint Proposal is premised on the Company's not filing for new gas base delivery rates that go into effect prior to May 20, 2011. If the Company seeks to establish new rates for its gas operations and such rates go into effect prior to May 20, 2011, then the Company will be required to defer for the benefit of gas customers an amount equal to the stay-out premium of $1.589 million in Rate Plan Year One, plus the *pro rata* portion of the stay-out premium of $1.589 million for Rate Plan Year Two recovered by the Company.[7] If the Company files for new gas base rates that go into effect after May 19, 2011, this deferral of the stay-out premium will not apply. The disposition of any deferred credit accrued in accordance with this provision will be determined by the Commission.

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[7] The *pro rata* portion of the stay-out premium will be based on the percentage of Rate Plan Year One's forecast delivery revenue from the beginning of the applicable rate plan year to the date new rates take effect, divided by Rate Plan Year One's total forecast delivery revenue. A sample calculation is provided at Appendix J.

3. Computation And Disposition Of Earnings

3.1 Earnings Report

By August 31st of each year, the Company will file an earnings report using the methodology described herein and shown in Appendix K. This earnings report will be used for the Earnings Sharing mechanism provided for in this Joint Proposal and for the limitation on recording deferred debits for increased costs relating to the following deferrals:

- Clause 4.2.1 Regulatory, Legislative and Accounting Changes
- Clause 4.4.4 Cost of Low Income Program
- Clause 4.4.6 NYSERDA Auction Rate Debt
- Clause 4.4.7 New Long-Term Debt Issuances
- Clause 4.4.8 PSC Assessment

This earnings report will calculate earnings for gas operations in each Earnings Year, incorporating the adjustments set forth below to arrive at an Average Earned Return On Equity for each two-year period. Any excess earnings that were subject to sharing in prior years will be excluded. In the event of a partial or “stub” period, the Earnings Sharing Threshold of 11.35% will be prorated to develop a stub period Earnings Sharing Threshold.

3.2 Capital Structure

The Company will calculate its Average Earned Return On Equity using the latest known capital structure of Niagara Mohawk’s ultimate parent (National Grid plc) for the fiscal year ended March 31st, adjusted for both US GAAP and the regulatory asset value of National Grid plc's regulated UK businesses, for each Earnings Year.[8]

3.3 Discrete Incentives

The Company will calculate its Average Earned Return On Equity by excluding the effects of the following discrete incentives:

- Customer Service Quality Revenue Adjustments (gas portion)
- Gas Safety and Reliability Revenue Adjustments
- Energy Efficiency Incentives
- Revenue Sharing For capacity release and off-system sales
- Revenue Sharing For S.C. 4 and S.C. 6
- LAUF Adjustments.

Any other discrete incentives approved by the Commission will also be excluded from the Company's calculation of Average Earned Return on Equity.

3.4 Pre-Rate Plan Period Adjustments

The Company will calculate its Average Earned Return On Equity by excluding the effects of any pre-Rate Plan period adjustments.

3.5 Earnings Sharing

If the Company's Average Earned Return On Equity for Earnings Year One and Earnings Year Two (*i.e.*, the 12 months ending May 31, 2010 and May 31, 2011, respectively) exceeds 11.35% ("Earnings Sharing Threshold"), then Niagara Mohawk will defer for refund to customers a credit as set forth below:

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8 Imputed debt will be priced at 6.9% for this calculation.

3.5.1 for the first 225 basis points above the Earnings Sharing Threshold of 11.35% (*i.e.* > 11.35%, but ≤ 13.6%), 50% of the revenue equivalent of earnings above the Earnings Sharing Threshold will be deferred for the benefit of customers and the remaining 50% will be retained by the Company;

3.5.2 for the next 200 basis points (*i.e.* > 13.61%, but ≤ 15.6%), 75% of the revenue equivalent of earnings above the Earnings Sharing Threshold will be deferred for the benefit of customers and 25% will be retained by the Company; and

3.5.3 90% of the revenue equivalent of all earnings in excess of 15.6% will be deferred for the benefit of customers and 10% will be retained by the Company.

Any credits resulting from the operation of this clause will be applied to the Company's net regulatory deferral account.

4. Reconciliations, Deferrals and True-Ups[9]

4.1 Existing Reconciliation, Deferral and True-Up Mechanisms

The following existing mechanisms will continue:

4.1.1 P&OPEB Costs

In accordance with the Commission's Policy Statement issued in Case 91-M-0890, the Company will defer and reconcile its actual annual P&OPEB expenses to the level allowed in rates. The pension expense associated with the Company's gas operations reflected in the Rate Plan Year One revenue requirement set forth in Appendix A is $4,967,484. The OPEB expense associated with the Company's gas operations reflected in the Rate Plan Year One revenue requirement is $16,091,633. Rate Plan Year

[9] Examples of the various deferral mechanisms are set forth in Appendix L.

Two P&OPEB expense levels, determined in Clause 2.3.1.2,[10] will be the basis for deferrals as of Rate Plan Year Two.

For purposes of computing the reconciliation of P&OPEB expenses, the Company will not include: (1) the gas operations portion of actual P&OPEB expenses associated with four additional consumer advocates that are reflected in gas operation expense; or (2) any separation and early retirement costs. Appendix L-1 reflects the methodology to be used to determine P&OPEB expense deferrals.

4.1.2 S.C. 9 Revenue Reconciliation

The Company will reconcile its actual annual S.C. 9 revenues to the amount of S.C. 9 revenues reflected in rates. The amount of annual S.C. 9 revenues reflected in rates is $11,380,293. Through an adjustment to base delivery rates pursuant to Rule 26 of the Company's tariff, the Company's customers will bear 100% of any shortfall in S.C. 9 revenues from the annual amount set forth in rates and will receive a credit for 100% of any S.C. 9 revenues received by the Company in excess of the annual amount reflected in rates. An example of this reconciliation is provided in Appendix L-2.

4.1.3 Off-System Sales Margins, Capacity Release Credits And Portfolio Optimization

Net margins from off-system sales, capacity release credits other than those associated with assignments to ESCOs and any net margins derived from the optimization of the Company's portfolio of gas supply, transportation, storage and peaking contracts will be shared 85% to customers and 15% to the Company. An illustrative example is provided in Appendix L-3. The customers' share of any margins

[10] The Company's P&OPEB funding requirements for Rate Plan Years One and Two will be as set forth in the pre-filed direct testimony of the Staff Accounting Panel in this proceeding at Tr 1609 – 1616, which transcript pages are incorporated herein by reference.

or credits will be credited to customers through the Company's Annual Reconciliation filing in accordance with Rule 17.7 of the Company's tariff.

4.1.4 Gas Costs

The Company will continue to recover and reconcile its cost of gas in accordance with Rule 17 of the Company's tariff.

4.1.5 Research And Development Millennium Fund Costs

The Company will continue to recover and reconcile research and development Millennium fund costs in accordance with Rule 30 of its tariff and the Commission's February 14, 2000 order in Case 99-G-1369.

4.2 Modifications To Existing Reconciliation, Deferral and True-Up Mechanisms

The following, existing mechanisms will continue as modified below:

4.2.1 Regulatory, Legislative And Accounting Changes

The Company will defer the gas portion of all rate plan year costs associated with the impact of discrete regulatory, legislative or accounting changes to the extent any such individual change has an impact that exceeds $2.283 million in any such year.[11] For cost increases, the Company will be allowed to establish a deferred debit in a rate plan year only if its actual earnings in the corresponding Earnings Year, as calculated in accordance with Clause 3 of this Joint Proposal, result in a return on equity that does not exceed 10.2%. For cost decreases, the establishment of a deferred credit is not subject to any earnings test.

[11] $2.283 million represents 5% of forecast net operating income after deductions for interest and taxes as of the Effective Date of this Joint Proposal.

As shown in Appendix L-4, in the event a discrete change has an impact that exceeds $2.283 million in a rate plan year, the Company will defer the entire impact of the change, not just the portion that exceeds $2.283 million. To the extent that the deferral of expense associated with any discrete change causes the Company to exceed the allowed ROE of 10.2%, the Company will be permitted to defer as much of the expense as does not cause the Company to exceed the allowed ROE of 10.2%.

4.2.2 <u>Site Investigation And Remediation ("SIR") Costs</u>

SIR costs and potential SIR cost offsets are defined in the same manner as described in Attachment 14 to the Joint Proposal dated October 11, 2001 and approved by the Commission in Case 01-M-0075,[12] except that SIR costs associated with the Company's gas operations will exclude any internal labor costs. For each rate plan year, the Company will defer and reconcile its actual, net gas-allocated SIR costs to the amount of SIR costs reflected in gas rates. Illustrative examples are provided in Appendix L-5. The amount of SIR costs associated with gas operations reflected in rates in Rate Plan Year One is $4,427,900, which amount excludes internal labor costs. As of the Effective Date, no carrying charges will be applied on SIR cost variances from the amount of such costs reflected in gas rates.

For Rate Plan Year Two SIR deferral purposes, actual SIR expenses will be compared to the SIR allowances set forth in Clause 2.3.1.3.

4.2.3 <u>S.C. 4 And S.C. 6 Delivery Revenue Sharing</u>

The amount of S.C. 4 delivery revenue reflected in the revenue requirement set forth on Appendix A is $603,115. The amount of S.C. 6 revenue reflected in the revenue

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[12] Attachment 14 to the October 11, 2001 Joint Proposal adopted by the Commission in Case 01-M-0075 is incorporated herein by reference.

requirement is $4,764,844. To the extent that the Company's actual annual S.C.4 and S.C. 6 delivery revenues differ from those respective amounts, the Company will retain or absorb 10% of the difference and customers will retain or absorb 90% of the difference through an adjustment to base delivery rates pursuant to Rule 26 of the Company's tariff. An example of the revenue-sharing mechanism is provided in Appendix L-2.

4.2.4 Weather Normalization

The Company's weather normalization adjustment set forth in Rule 27 of the Company's tariff will be modified to eliminate the existing 2.2% deadband for all service classifications subject to such adjustment.

4.3 Existing Deferral, Reconciliation and True-up Mechanisms To Be Eliminated

As of the Effective Date, the calculation of the gas portion of the fixed and incentive returns on the $209 million of pre-funded P&OPEB costs will cease.

4.4 New Deferral, Reconciliation and True-Up Mechanisms

The following new deferral/reconciliation and/or true-up mechanisms will be implemented as of the Effective Date:

4.4.1 Gas Supply Procurement Costs

The Company's proposed Merchant Function Charge rate reflects the recovery of $1,064,825 of gas supply procurement costs divided by 542,927,136 therms, which is the projected throughput for S.C. 1, 2, 12 and 13 customers purchasing supply service from the Company. On an Earnings Year basis, the Company will reconcile and defer the recovery of this cost for differences between actual and forecast throughput, as shown in Appendix L-6.

4.4.2 Carrying Costs On The Cost Of Gas In Storage

Appendix L-7 sets forth projected monthly quantities and prices of the Company's balances of gas in storage for the 12 months ending March 31, 2010. As shown in Appendix L-7, the projected average balance of the cost of gas in storage in that year is $61,828,183 for SC 1, 2, 12 and 13 customers purchasing their commodity from the Company. On an Earnings Year basis, the Company will true up, through a change in the Merchant Function Charge, its carrying costs on the cost of gas in storage for: (1) changes in the cost of gas; and (2) differences between actual and forecast throughput.

To compute the true up for changes in the cost of gas for each Earnings Year, the Company will first calculate the actual average inventory balance on a traditional rate base 13-point average basis for S.C. 1, 2, 12 and 13 customers, based on monthly volumes totaling 110,003,357 Dth priced at the Company's actual weighted average cost of gas in storage per Dth for each month, and multiplied by .990828212 to exclude S.C. 3. The calculation of the average inventory balance will not reflect changes in the monthly volumes of gas in storage. Rather, the volume of gas in storage will be fixed at 110,003,357 Dth, as set forth on Appendix L-7. The difference between the actual average inventory balance thus calculated and the projected balance for the Earnings Year will be multiplied by the Company's allowed 10.69% pre-tax weighted average cost of capital to determine the variance in carrying costs associated with changes in the cost of gas. This variance will be combined with any over/under collection of carrying costs associated with differences between actual and forecast sales to arrive at the total true-up amount for the Earnings Year, which will be reflected in the Merchant Function Charge for the twelve months commencing with the ensuing month of September.

The return on the cost of gas in storage inventory component of the Merchant Function Charge will be reset at the start of each Earnings Year by first calculating the projected average balance of storage inventory assuming volumes of 110,003,357 Dth, priced at the Company's forecast weighted average cost of gas in storage (per Dth) for each month of the Earnings Year. The resulting projected average inventory cost will be multiplied by .990828212 to exclude S.C. 3, then multiplied by the 10.69% pre-tax weighted average cost of capital, and finally divided by projected throughput for S.C. 1, 2, 12 and 13 customers purchasing commodity from the Company for the Earnings Year to arrive at a per therm rate.

4.4.3 RDM

The Company will defer and true-up RDM differences between actual and allowed delivery service revenues, as described in Clause 2.2.5, through an adjustment to base delivery rates.

4.4.4 Low Income Program Costs

As discussed in Clause 6.1 below, the cost of the Low Income Program reflected in the customer charge of all firm service classes will be $4.5 million annually.[13] For each rate plan year, the Company will defer and reconcile the amount recovered in rates to the actual cost of the Low Income Program in that year. All such reconciliations will be on a rate plan year basis. If the actual annual program costs exceed the amount actually recovered in rates, the Company will be permitted to establish a deferred debit in a rate plan year only if its actual annual earnings in the corresponding Earnings Year, as calculated in accordance with Clause 3 of this Joint Proposal, result in a return on equity

[13] Low Income Program costs equal the gas delivery rate credit of $7.50 per month (as prorated for bill cycles shorter than 25 days and longer than 35 days) multiplied by the number of customers receiving the credit in each month.

that does not exceed 10.2%. If the actual annual Low Income Program costs are less than the amount actually recovered in rates, the establishment of a deferred credit is not subject to any earnings test. To the extent that the deferred debit causes the Company to exceed the 10.2% ROE threshold, the Company will be permitted to defer as much of the net incremental expense as does not cause the Company to exceed the 10.2% ROE threshold. An example of this reconciliation is set forth in Appendix L-8.

4.4.5 Under Spending Of Capital Expenditures

The Company's forecast of capital expenditures for gas operations for the 12 months ending March 31, 2010 is $69,073,755. To the extent the Company spends less than this amount in the twelve months ending March 31, 2010 for capital expenditures, it will defer the full Rate Plan Year One revenue requirement impact, including both return of and return on capital, associated with any under spending. The Company will record a regulatory credit for only the amount of the revenue requirement impact of the one year only; no further credits in subsequent years will be recorded. Any capital expended by the Company: (1) to replace coated steel services or (2) on common plant will not be reflected in the calculation of this reconciliation. Appendix L-9 provides an illustrative example of the true up of the revenue requirement impact.

4.4.6 NYSERDA Auction Rate Debt

Attached in Appendix L-10 is an update to Exhibit 114 (PP/KD-11), which sets forth, *inter alia*, the forecast of the interest costs, insurance premiums and remarketing fees associated with NYSERDA auction rate debt issued by the Company that are reflected in the revenue requirement. Beginning on May 20, 2009, the Company will fully reconcile its actual interest costs, insurance premiums and remarketing fees associated with the NYSERDA auction rate debt to the corresponding costs, premiums and fees set forth on Appendix L-10. For cost increases, the Company will be allowed to establish a deferred debit in a Rate Plan Year only if its actual earnings in the corresponding Earnings Year, as calculated in accordance with Clause 3 of this Joint Proposal, result in an ROE that does not exceed 10.2%. For cost decreases, the establishment of a deferred credit is not subject to any earnings test. To the extent that deferral of interest costs, insurance premiums or remarketing fees causes the Company to exceed the 10.2% ROE threshold, the Company will be permitted to defer as much of the increased cost as does not cause the Company to exceed the 10.2% ROE threshold. This reconciliation mechanism will expire at the end of Rate Plan Year Two (May 19, 2011).

4.4.7 New Long-Term Debt Issuances

The revenue requirement set forth in Appendix A reflects the portions of two new debt issuances that are allocable to Niagara Mohawk gas operations. The first of those new issuances, in the amount of $750 million, is assumed to have been issued prior to the beginning of Rate Plan Year One and the costs associated with that issuance are thus fully reflected in the revenue requirement for Rate Plan Year One. The second of these new issuances, in the amount of $500 million, is assumed to be issued on October 1, 2009 and thus only a portion of the costs associated with this issuance are reflected in the Rate Plan Year One revenue requirement. The costs of these long-term debt issuances are reflected in the revenue requirement at 6.9%, which includes all interest and issuance costs.

The Company will establish two gas true-up mechanisms that cover the period May 20, 2009 through May 19, 2011. These gas true-up mechanisms will be calculated on a daily basis, but will be booked as accruals on a monthly basis.

The first gas true-up mechanism will true up the actual interest rate of the first $1.25 billion of debt issued under the Commission's Order in Case 08-M-1352 through May 19, 2011 to the baseline interest rate of 6.9% assumed in establishing rates. The 6.9% baseline rate includes the amortization of all issuance costs. The true up will be 100% of interest and amortization of issuance costs above 7.05% and below 6.75% (a dead band of 15 basis points above and below the baseline rate of 6.9%) of all newly issued debt, multiplied by 17.85% (*i.e.*, the portion of the $1.25 billion of debt that supports forecast gas rate base). The second gas true-up mechanism will true up the amount, cost and timing of the first $1.25 billion of debt issued under the Commission's Order in Case 08-M-1352 to the amount, cost and timing included in gas rates in this proceeding. The purpose of the second true-up is to ensure that the Company's future actual debt issuances occur coincidentally with the time period assumed in establishing rates. The second true-up mechanism will compare the timing and amount of debt actually issued under the Commission's Order in Case 08-M-1352 (up to the first $1.25 billion) with the timing and amount of new debt forecast to be issued (and included in rates) in Appendix L-10 (up to the first $1.25 billion). This second true-up mechanism will not apply in the event and as of the time the Company has actually issued more new debt under the Order in Case 08-M-1352 than is projected in Appendix L-10 (up to the first $1.25 billion). If for any time period, up to and including May 19, 2011, the Company has actually issued less new debt under the Order in Case 08-M-1352 than was projected in Appendix L-10 (up to the first $1.25 billion), a deferred credit will be calculated under this second true-up mechanism. The deferrals related to this second true-up mechanism are based on 17.85% of the total amounts calculated. Illustrative calculations of both deferrals are contained in Appendix L-11.

For cost increases, the Company may establish a deferred debit for the first gas true-up mechanism in a rate plan year only if its actual earnings in the corresponding Earnings Year, as calculated in accordance with Clause 3 of this Joint Proposal, result in an ROE that does not exceed 10.2%. For cost decreases, the establishment of a deferred credit for either or both true-up mechanisms is not subject to any earnings test. To the extent that deferral of interest and issuance costs causes the Company to exceed the 10.2% ROE threshold, the Company will be permitted to defer as much of the increased cost as does not cause the Company to exceed the threshold. This reconciliation mechanism will expire at the end of Rate Plan Year Two (May 19, 2011).

4.4.8 <u>PSC Assessment</u>

The amount of the PSC gas assessment (including the NYSERDA assessment) reflected in the gas revenue requirement set forth on Appendix A is $3,727,500. To the extent the Company's actual annual PSC assessment expense for gas operations, prorated for the rate plan year, differs from this amount, the Company will defer the difference, as illustrated in Appendix L-12. For expense increases, the Company will only be allowed to establish a deferred debit in a rate plan year if its actual earnings in the corresponding Earnings Year, as calculated in accordance with Clause 3 of this Joint Proposal, result in a return on equity that does not exceed 10.2%. For expense decreases, the establishment of a deferred credit is not subject to any earnings test. In addition, to the extent that the deferred incremental PSC assessment expense causes the Company to exceed the 10.2% ROE threshold, the Company will be allowed to defer as much of the expense as does not cause the Company to exceed the 10.2% ROE threshold.

4.4.9 Late Payment Charges

The level of gas commodity-related Late Payment Charges included in the revenue requirement attached as Appendix A is $1,711,070. To the extent that calculated commodity-related late payment charges differ from this amount, the Company's base delivery rates will be adjusted monthly to charge or refund the difference to customers. An example of the calculation of late payment charges is provided in Appendix L-13.

4.5 Other Issues Associated With Deferrals/Reconciliations And True-Ups

4.5.1 Carrying Costs On Deferred Balances

Except for RDM and as specified in the Company's tariffs, carrying costs will not be accrued on deferred debit or credit balances.

4.5.2 Customer Services System ("CSS") Deferral

The CSS deferral issue raised in the direct testimony of the Staff Accounting Panel is not resolved by this Joint Proposal. This issue may be raised and resolved, without prejudice to any party's position in this Joint Proposal, in the compliance filing phase of Case 07-M-0943.

4.5.3 Compounding Of Pre-Rate Plan Year One Gas Contingency Reserve Carrying Charges

In its rebuttal testimony in this proceeding, the Company's Expense Panel took issue with the Staff Accounting Panel's calculation of carrying charges on pre-Rate Plan

Year One Gas Contingency Reserve balances, citing Staff's alleged failure to use a monthly compounding rate with a time value of money discount factor. This Joint Proposal resolves all issues related to the compounding of interest on pre-Rate Plan Year One Gas Contingency Reserve balances.[14] The agreed upon methodology is set forth in Appendix M.

4.5.4 Gas Contingency Reserve Reconciliation Report

The Company will file with the Commission a Gas Contingency Reserve Reconciliation Report reflecting all of the adjustments to the Gas Contingency Reserve resulting from this Joint Proposal within 60 days of a Commission Order adopting this Joint Proposal.

4.5.5 Net Regulatory Asset Balance Issues Not Resolved

The fact that the revenue requirement reflects the Company's forecast net regulatory asset balance at April 30, 2009 does not mean that all issues associated with that balance are resolved. This Joint Proposal only resolves those issues associated with deferred balances at April 30, 2009 that were explicitly raised in Staff's and the Company's testimony. This Joint Proposal does not resolve deferral issues that were not raised in testimony, and it does not resolve deferral issues that are pending in other proceedings.

4.5.6 Future Disposition Of Deferred Balances

The Company will continue amortizing the net regulatory asset at a monthly rate of $1,225,583 and will continue crediting the deferred account for the same amount until such time as new gas base delivery rates become effective in the Company's next gas

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[14] The pre-Rate Plan Year One Gas Contingency Reserve balances agreed to in this Joint Proposal do not use the Company's proposed monthly compounding rate with a time value of money discount factor.

base rate proceeding. The rate treatment of the net regulatory asset deferred balances resulting from the deferrals set forth herein, the difference between the net regulatory deferred balance reflected in the revenue requirement and the actual balance as of May 19, 2009, and any net regulatory credit arising from continued amortization of the net regulatory asset at a rate of $1,225,562 per month beyond the expiration of Rate Plan Year Two, will be decided by the Commission in the Company's next gas rate proceeding. Likewise, if the Company files for new gas base rates that go into effect before the expiration of Rate Plan Year Two, the rate treatment of the remaining unamortized net regulatory asset deferred balances will be decided by the Commission in the Company's next gas rate proceeding.

4.5.7 <u>Deferrals Associated With Reallocations Or Reclassifications Of Costs Between Electric And Gas Business Units</u>

In the future, if the Company files for an electric base rate increase, but does not, at the same time, file for a gas base rate increase, then a deferred gas debit or credit, as appropriate, will be established for any costs reallocated or reclassified to or from the gas business.[15] The Signatory Parties agree that this result is consistent with the intent of Clause 1.2.3.5 of the Joint Proposal dated October 11, 2001 and adopted by the Commission in Case 01-M-0075.

5. <u>Additional Rate Provisions</u>

5.1 <u>Service Quality Issues</u>

The Company presently has a Service Quality Assurance Program that contains the following six performance measures:

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[15] The baseline for measuring such deferrals will be the allocations and classifications inherent in setting the gas base rates in this proceeding.

(a) PSC Complaint Rate;

(b) Residential Customer Transaction Satisfaction Index;

(c) Small/Medium Commercial and Industrial Customer Satisfaction Index;

(d) Percent of Meters Read;

(e) Percent of Calls Answered Within 30 Seconds; and

(f) Low Income Customer Assistance Program enrollment.

The Company's failure to meet the standards established for these performance measures on an annual basis results in downward revenue adjustments that range from a minimum to maximum level depending on the Company's performance.

The downward revenue adjustments associated with the following performance measures will be revised for the gas business as of the Effective Date:

Performance Measures	New Minimum Revenue Adjustment	New Maximum Revenue Adjustment
PSC Complaint Rate	$200,000	$1,600,000
Residential Transaction Satisfaction Index	$100,000	$800,000
Small/Medium Commercial And Industrial Satisfaction Index	$100,000	$800,000
Percentage of Calls Answered Within 30 Seconds	$100,000	$800,000

Any negative revenue adjustments assessed for calendar year 2009 will be pro-rated to reflect the May 20, 2009 Effective Date for the revised revenue adjustments.

In addition, no later than June 30, 2009, the Company will convene a collaborative for the purpose of developing monthly surveys as a replacement for the current quarterly surveys that are used to measure residential customer transaction satisfaction and small/medium commercial and industrial customer satisfaction. The collaborative will also consider how the transition from quarterly to monthly surveys will be reflected in the determination of downward revenue adjustments. The parties will use their best efforts to resolve issues through the collaborative process by August 30, 2009. The Company will file a report concerning the results of the collaborative no later than September 30, 2009 for such further Commission action as may be necessary.

5.2 <u>Safety And Reliability Performance Measures</u>

In calendar year 2011, certain of the damage targets applicable to the Company's Safety and Reliability Performance Measure will be adjusted to the following levels (number of damages per 1,000 one-call tickets).

(a) Overall damages – 3.94

(b) Mismarks – 0.67

(c) Company and Contractor damages – 0.19

These revised targets will remain in effect until changed by the Commission. All other targets in the Safety and Reliability Performance Measure and the associated revenue adjustments established by the Commission for the Company in its September 17, 2007 Order in Case 06-M-0868 will remain unchanged.

5.3 <u>Purchase Of Receivables ("POR") Discount Rates</u>

5.3.1 <u>Discount Rate For Uncollectibles</u>

As of the Effective Date, the Company will implement separate POR discount rates for the uncollectible components applicable to the S.C. 1 and non-residential service classifications. The discount rates will reflect the 2.3% uncollectible rate for S.C. 1 and the 0.3% rate for the non-residential service classes.

5.3.2 <u>Assessment Of Credit And Collections Processing Costs</u>

As of the Effective Date, in lieu of including in the discount rate a factor to recover collections processing costs, the Company will implement a separate charge for collections processing costs equal to $0.00419 per therm that will be assessed to ESCOs participating in the POR program. The charge will be based on deliveries to the ESCOs' customers. A charge of the same magnitude will be assessed to sales customers through the Merchant Function Charge. Together, these charges will permit the Company to recover its credit and collections processing expense of $2,912,071; however, the Company's recovery of credit and collections processing expense will not be subject to true up.

6. <u>Miscellaneous Programs, Reporting Requirements And Tariff Issues</u>

6.1 <u>Low Income Program</u>

As of the Effective Date, the Company will implement a low income program that will provide a gas service delivery credit of $7.50 per month. Customers eligible for this program will include any customer who has received a Home Energy Assistance Program ("HEAP") grant within the previous 14 months. The Company will file an annual report to show the actual number of participants in the program and the associated bill credits with the Director of Consumer Services by June 30th of each year. The cost of the program will be recovered in base rates from each firm service classification as described in Clause 4.4.4 above, with cost/recovery reconciliation as provided in Appendix L-8. To enhance the AffordAbility Program, the Company will increase the credit allowed to gas customers enrolled in its arrears forgiveness program by $10 per month, for a total of $30 per month.[16] The Company will continue to submit the required quarterly and biennial evaluation for the AffordAbility program to assess its effectiveness. Finally, as of the Effective Date, the Company will provide a one-time $40 benefit to all elderly, blind, disabled or life support equipment customers for whom the Company receives a HEAP grant.

6.2 Depreciation Study

The agreed upon depreciation rates and curves are set forth in Appendix C. When the Company next files for new gas rates, its initial filing will include a full Depreciation Study. The study will include rolling and shrinking band analyses for each depreciable plant account, the Fit Index, Average Service Life and graphs showing the observed proportion surviving, the observed curve and selected h-curve. The Company will also provide a net salvage study for each depreciable plant account that includes, at a minimum, rolling five-year band analyses of gross salvage, cost of removal and net salvage for each account.

Beginning January 1, 2010, the Company will establish two sub accounts, for Account 380 - Services *i.e.*, metallic and nonmetallic, and will prospectively classify and record gas services in these sub accounts.

In addition, the Company will include in its initial filing a calculation of the depreciation reserve imbalances for each plant account.

[16] Niagara Mohawk's electric-only customers will not be eligible for this $10.00 increase; their credit will remain at $20.00.

6.3 Monthly Balancing Charge For Daily Balanced Customers

The Monthly Balancing Charge for daily metered customers will be removed from the tariff and included in a Monthly Statement that will be updated to reflect changes in Dominion Transmission Inc.'s storage service. In addition, the Company will replace its Seasonal Imbalance Tolerance with a uniform tolerance of 5%. If any customer requests an imbalance tolerance of greater than 5%, such tolerance (if available) will be subject to an additional charge, which will require Commission approval.

6.4 Procurement Of Interruptible Capacity

The Company will continue its present practice of procuring non-firm capacity for monthly balanced customers during the months of April and October.

6.5 Standby Sales Service

Standby sales service to S.C. 8 customers will be priced at the daily weighted average cost of gas. (The "daily weighted average cost of gas" is defined as the weighted average price of flowing supply and storage withdrawals, including variable transportation, to the citygate for that day).

The nomination deadline will be modified so that nominations will be due by 8:00 a.m on the business day before the day the gas will be consumed. For example, for a gas day commencing at 10:00 a.m. on Thursday, nominations are due by 8:00 a.m. on Wednesday, the prior day. For informational purposes, by 3:00 p.m. each business day, the Company will provide a preliminary calculation of the daily weighted average cost of gas for the previous gas day, including holiday and weekend days.

6.6 Tariff Changes

The Company will be permitted to implement the following tariff changes as of the Effective Date:

(i) Tariff Leaves 179 and 180 will be modified to recognize that allocations of assigned upstream storage and transportation capacity may need to be modified as customer requirements change, subject to Commission approval of future tariff filing(s);

(ii) Tariff Rule 5.2 will be revised to delete the words "sole use;"

(iii) Tariff Rule 16.1 will be revised to apply to "customers" and "applicants;"

(iv) Tariff Rule 13.5.4 will be revised to modify the circumstances in which a penalty is imposed on daily balancing customers as a result of a non-operational Approved Remote Metering unit (ARM). Specifically, if the ARM failure is attributable to inactive phone or electric service and this condition continues for ten days, the customer will be charged $115.00 per day until the ARM becomes operational.

(v) Tariff Rule 20 will be revised to modify the re-establishment changes from $41 to $53.13 during normal business hours and from $111.00 to $70.58 during other than normal business hours.

(vi) The Company may at any time file tariff revisions to change the way gross revenue taxes are collected from customers and this Joint Proposal will not affect the resolution of any such filing.

6.7 Outreach And Education Plan

The Company will file no later than January 1st an annual Outreach and Education Plan with the Office of Consumer Services. This filing will include detailed budgets and will describe the specific outreach campaign message to be disseminated, the communication vehicle to be used to disseminate the message, the goals of the outreach program and the criteria for measuring their achievement. The plan will continue to include information regarding retail access. In addition, the Company's welcome letter to new customers will continue to inform customers that they have the option to buy their natural gas from an independent ESCO and will make available a list of participating ESCOs.

6.8 Gas Marketing Program

The Company will maintain its books and records in a manner that will permit the segregation of any expenses associated with a Gas Marketing Program from Outreach and Education and Energy Efficiency Program expenses.

6.9 Construction Work In Progress Work Orders

The Company will file with the Commission two studies of construction work in progress work orders with no activity for six months or more based on data as of May 31, 2008 and December 31, 2008. The first study will analyze gas and common work orders and will be due no later than July 20, 2009. The second study will analyze electric work orders and will be due no later than August 20, 2009.

The study of gas and common work orders will analyze work orders in excess of $10,000, but any Commission activity taken as a consequence of the study will be applied ratably to work orders of less than $10,000. The study of electric work orders will analyze work orders in excess of $10,000, but any Commission action taken as a consequence of the study will be applied ratably to work orders of less than $10,000.

For each work order analyzed, the Company will provide an explanation and any supporting data as to:

(i) why the work is used and useful;

(ii) the date the inactivity started;

(iii) the date the inactivity ended;

(iv) the date the work order was operationally placed in service;

(v) the reason and justification for the inactivity duration;

(vi) a description of the additional work performed and the dates and amounts of the additional work performed after the period of inactivity;

(vii) the amount of allowance for funds used during construction, if any, accrued during inactivity and closed to plant in service; and

(viii) the applicable depreciation rates.

Staff's agreement to the temporal parameters of May 31, 2008 and December 31, 2008 for the Company's studies does not preclude Staff from taking a position in Niagara Mohawk's next gas and/or electric base rate proceeding that a depreciation and/or a used and useful adjustment is/are warranted for a period that differs from such parameters; nor does it diminish in any respect Staff's oversight responsibilities or rights to access the Company's records; nor does it preclude the Company or any other party from taking any position concerning any adjustment that may be proposed in the future.

6.10 <u>Account 106 Balances</u>

Following the Effective Date, the Company will provide quarterly reports concerning aged Account 106 Balances. These reports will identify the amounts included in Account 106 that have remained unclassified for (i) more than six months, (ii) more than twelve months; and (iii) more than eighteen months.

6.11 <u>Capital Expenditure Reports</u>

No later than April 30th of each year, the Company will file a report setting forth (i) its actual capital expenditures for the previous twelve months ending March 31st, and (ii) its forecast of capital expenditures for the subsequent twelve months ending March 31st. The format of this report is attached as Appendix O.

6.12 <u>High Pressure Bare Steel Services</u>

As part of its annual reports on gas safety and reliability performance measures due April 30, 2010 and April 30, 2011, the Company will report the number of bare steel services it replaced during the 12 months ended March 31, 2010 and March 31, 2011, respectively.

7.0 <u>Miscellaneous Provisions</u>

7.1. <u>Future Actions/Dispute Resolution</u>

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

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

7.2. No Severability

Each provision of this Joint Proposal is in consideration and support of all other provisions, and the Signatory Parties' agreement with each provision is expressly conditioned upon the acceptance of the Joint Proposal in its entirety by the Commission. In the event or to the extent that the Commission does not adopt this Joint Proposal in its entirety, the Signatory Parties will be free to pursue their respective positions in this proceeding and any remedies at law or in equity without prejudice.

7.3. Commission Action on This Joint Proposal

The Signatory Parties intend that this Joint Proposal will be approved by the Commission as being in the public interest and agree individually to advocate its adoption by the Commission in its entirety and to act so as to expedite the Commission's approval of this Joint Proposal.

If the Commission modifies any provision in this Joint Proposal, the Company may choose not to accept it as modified; in that event, Niagara Mohawk will serve notice on the active parties. The Signatory Parties expect that the Commission would act consistently with its Opinion 92-2, "Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines" in Case 92-M-0138 (March 24, 1992) in connection with any modification to the Joint Proposal.

7.4. No Precedent

The provisions of this Joint Proposal apply solely to and are binding only in the context of this Joint Proposal and this proceeding. None of the terms of this Joint

Proposal and none of the positions taken by any active party with respect to this Joint Proposal may be referred to, cited by or relied upon by anyone in any manner as precedent or otherwise in any other proceeding before the Commission or any other regulatory body or before any court of law for any purpose other than the adoption, implementation, furtherance or extension of this Joint Proposal. None of the Signatory Parties will be deemed to have approved, agreed to, or consented to any principle or methodology underlying or purported to underlie any agreement provided for herein.

7.5. Continuation

To the extent they are not explicitly eliminated, modified or replaced by this Joint Proposal, all current elements of Niagara Mohawk's gas rates will continue for the two-year term of this Joint Proposal. Except as expressly stated herein, all provisions of this Joint Proposal will continue until changed by order of the Commission. For those provisions in this Joint Proposal that establish targets, the targets in effect in Rate Plan Year Two will apply to subsequent years.

7.6. Extension

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

7.7. Rate Changes During Rate Plan

Changes to the Company's base delivery rates during the term of the rate plan are permitted, subject to Clause 2.3.4 of this Joint Proposal. In addition, the following actions will not trigger deferral of the stay-out premium under Clause 2.3.4 of this Joint Proposal and are otherwise permissible:

a. Niagara Mohawk may petition the Commission to implement changes to its gas rates or charges as may be required or warranted by newly-enacted legislation or regulations;

b. The Company retains the right to petition the Commission for deferral of extraordinary expenses not addressed by this Joint Proposal; other parties retain the right to petition the Commission for deferral of extraordinary expense reductions not addressed by this Joint Proposal;

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

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

e. The Company may file tariff amendments to implement changes as described in Clause 6.6(vi);

f. Niagara Mohawk may petition the Commission for minor changes in base rates, provided the effect is *de minimis* or is essentially offset by associated changes in other base rates, statements, terms or conditions of service;

g. For any revenue change that may result from Commission action on any of the petitions described in this clause, the RPC factors will be adjusted, as appropriate; and

h. Any party may oppose any filing made by the Company pursuant to this Clause 7.7.

7.8. Entire Agreement

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

7.9 Commission Authority

Nothing in this Joint Proposal shall be construed to limit the Commission's authority to reduce the Company's gas rates should it determine, in accordance with the Public Service Law, that the established rates are in excess of just and reasonable rates or are inadequate for the provision of safe, reliable and adequate service.

Nothing in this Joint Proposal shall be construed to limit the Commission's authority to address the Company's customer service, reliability and/or safety measures in accordance with the Public Service Law.

7.10 Execution in Counterpart Originals

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

AGREED to this 13th day of February 2009.

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

By: ___________________________________

Party: ___________________________________

Date: ___________________________________

List of Appendices

Appendix	Description
A.	Revenue Requirement and support
B.	Regulatory Assets & Liabilities Forecast Balances at April 30, 2009
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O.	Section 6.11 – Gas Operations Capital Expenditure Report

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
Statement of Gas Operating Income
For the Rate Year Ending March 31, 2010
($000's)

	Corrections & Updates Filing Rate Year Ending March 31, 2010		Staff Adjustments	Rate Year Ending March 31, 2010	Base Revenue Increase Required	Rate Year Ending March 31, 2010 with Base Revenue Requirement
Operating Revenues	$ 871,949	(1)	$ (97,838)	$ 774,111	$ 39,428	$ 813,539
Deductions						
Purchased Gas Costs	584,636		(97,983)	486,653		486,653
Revenue Taxes	8,141		(1,664)	6,477	670	7,147
Total Deductions	592,777		(99,647)	493,130	670	493,800
Gross Margin	279,172		1,809	280,981	38,758	319,739
Total Operation & Maintenance Expenses	125,811	(2)	(9,434)	116,377	690	117,067
Amortization of Regulatory Deferrals	21,887	(3)	(7,180)	14,707		14,707
Depreciation, Amort. & Loss on Disposition	43,663	(4)	(2,816)	40,847		40,847
Taxes Other Than Revenue & Income Taxes	39,672	(5)	(443)	39,229		39,229
Total Operating Revenue Deductions	231,033		(19,873)	211,160	690	211,850
Operating Income Before Income Taxes	48,139		21,682	69,821	38,068	107,889
Income Taxes						
Federal Income Taxes	5,750		6,028	11,778	12,378	24,156
State Income Taxes	462		1,316	1,778	2,703	4,481
Total Income Taxes	6,212		7,344	13,556	15,081	28,637
Operating Income After Income Taxes	$ 41,927		$ 14,338	$ 56,265	$ 22,987	$ 79,252
Rate Base	$ 1,077,494	(6)	$ (48,242)	$ 1,029,252		$ 1,029,252
Rate of Return	3.89%			5.47%		7.70%
Return On Equity	2.06%			5.10%	$ 39,428	10.20%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
Gas - Operation & Maintenance Expenses
($000's)

	Corrections & Updates Rate Year Ending March 31, 2010		Staff Adjustments	Rate Year Ending March 31, 2010
Operation & Maintenance Expenses:				
Departmental Items:				
Consultants	$ 1,644	a	$ (68)	$ 1,576
Contractors	9,354		0	9,354
Donations	0		0	0
Employee Expenses	1,089		0	1,089
Hardware	899		0	899
Software	1,636		0	1,636
Other	3,515	b	(175)	3,340
Miscellaneous Expense	0	c	(2,643)	(2,643)
Rents	2,538	d	(197)	2,341
Service Co. Equity	(680)		0	(680)
Construction Reimbursement	(4)		0	(4)
Co Contributions/Cr to Jobs	0		0	0
Bill Interface Expense Type	139		0	139
Capital Overheads	0		0	0
Supervision & Admin	31		0	31
Service Co Operating Costs	10		0	10
Sales Tax	242		0	242
FAS 106	16,263	e	9	16,272
FAS 112	579		0	579
Health Care	4,556		0	4,556
Group Life Insurance	434		0	434
Other Benefits	140		0	140
Pension	4,625	f	401	5,026
Thrift Plan	1,171		0	1,171
Combined Fringe Benefits Adjustment	0	g	(479)	(479)
Workers Comp	463		0	463
Payroll Taxes	0		0	0
Materials Outside Vendor	3,550		0	3,550
Materials From Inventory	1,439		0	1,439
Materials Stores Handling	239		0	239
Total Labor	46,264	h	(1,178)	45,086
Regular Pay Weekly	0		0	0
Regular Pay Monthly	0		0	0
Base OT Pay Weekly	0		0	0
Incremental OT Pay Weekly	0		0	0
Base OT Pay Monthly	0		0	0
Incremental OT Pay Monthly	0		0	0
Bonus & Misc Pay	0		0	0
Time Not Worked	0		0	0
Transportation	4,728		(268)	4,460
Accounting Changes	264		0	264
Accrued Vacation Liability	46		0	46
Injuries & Damages	1,462		0	1,462
New Initiatives	1,040	i	(1,040)	0
Productivity Adjustment	(965)	j	40	(925)
Regulatory Assessment Fees	3,728		0	3,728
Site Investigation & Remediation Exper	4,500	k	(72)	4,428
Synergy Savings	(4,416)	l	(2,007)	(6,423)
System Benefits Charge	0		0	0
Uncollectible Accounts	15,681	m	(2,151)	13,531
Sub Total - Departmental	$ 126,205		$ (9,828)	$ 116,377
Non-Departmental Items:				
Purchased Power	0		0	
Purchased Gas	584,636		0	584,636
Sub Total - Non-Departmental	$ 584,636		$ -	$ 584,636
TOTAL	$ 710,841		$ (9,828)	$ 701,013

Niagara Mohawk, a National Grid Company
PSC Case No. 08-G-0609
Staff's Capital Structure Forecast
For the Rate year Ending March 31, 2010

Staff's Capital Structure Forecast

	Total NM Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 2,947,070	51.10%	6.15%	3.14%	3.14%
Short-Term Debt	232,500	4.03%	1.18%	0.05%	0.05%
Gas Supplier Refunds	-	0.00%	5.35%	0.00%	0.00%
Customer Deposits	37,890	0.66%	4.85%	0.03%	0.03%
Preferred Stock	29,270	0.51%	3.62%	0.02%	0.03%
Common Equity	2,520,111	43.70%	10.20%	4.46%	7.43%
Total	$5,766,841	100.00%		7.70%	10.69%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
Summary of Gas Rate Base
For the Rate Year Ending March 31, 2010
($000's)

	Corrections & Updates Rate Year Ending March 31, 2010	Adj.	Staff Adjustments	Rate Year Ending March 31, 2010
Net Utility Plant	1,179,349	a	(4,951)	1,174,398
Regulatory Assets / Liabilities	(16,591)	b	(5,099)	(21,690)
Accumulated Deferred Income Taxes - Federal	(180,202)	c	(11,629)	(191,831)
Accumulated Deferred Income Taxes - State	(9,720)	d	(3,504)	(13,224)
Working Capital				
Gas Storage	81,979		(19,406)	62,573
Materials and supplies	4,763	e	(1,400)	3,363
Prepayments	11,753		0	11,753
O&M Cash Allowance (1/8 O&M exp)	13,766	f	(910)	12,856
Supply Cash Allowance (2007 lead/lag study)	31,747		0	31,747
Change in Supply Cash Allowance (5.66% x RY Gas exp)	1,343		0	1,343
subtotal Working Capital	145,351		(21,716)	123,635
subtotal avg. before EBCAP adj.	1,118,187		(46,899)	1,071,288
Excess Earnings Base adjustment	(40,693)	g	(1,343)	(42,036)
Total Gas Rate Base	1,077,494		(48,242)	1,029,252

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
PSC Staff Direct Case
Staff Adjustments for the Rate Year Ending March 31, 2010
($000's)

Adj. 1.a	**Operating Revenues**		
a.	Increase Delivery Margin	$ 2,110	
b.	Increase Re-establishment revenues	$ 42	
c.	Increase Miscellaneous Revenues	190	
d.	Correct Staff's sales adjustment	115	
e.	Change in Late Payment Charges related to change in gas commodity costs	(392)	
f.	Staff concession of SC-1 sales adjsutment	(200)	
g.	Staff concession of miscellaneous revenue & re-establishment charges	(54)	
h.	Change in commodity revenues due to change in commodity costs	(99,649)	
	Total Operating Revenue Adjustments		$(97,838)
Adj. 1.b	**Purchased Gas Costs**		
	To reflect the change in commodity costs		$(97,983)
Adj. 1.c	**Revenue Taxes**		
	To reflect change in revenue taxes on adjustments 1.b - 1.h		$ (1,664)
Adj. 2	**Operating and Maintenance Expenses**		
a.	**Consultant Expense**		
	To remove one time Key Span integration costs from historic test year base, as per IR DAG-23		$ (68)
b.	**Other Expense**		
	To eliminate portion of AGA and NGA annual membership fees related to lobbying		$ (175)
c.	**Miscellaneous Expense**		
(1)	To reduce miscellaneous expense for O&M expenses allocable to affiliates using the Company's CSS	(143)	
(2)	To reflect reduced rate year expense levels due to allocation of airplane related O&M to affiliates	(21)	
(3)	To reflect commodity related collection processing expenses recoverable from ESCOs through the POR discount	(520)	
(4)	To reflect projected savings from additional gas mains and gas services replacements	(133)	
(5)	To reflect savings and efficiencies resulting from meeting the goals of the bonus pay program	(1,847)	
(6)	Staff concession of adjustment c.(2)	21	
			$ (2,643)
d.	**Rent Expense**		
	To allocate a portion of carrying charges on NMPC properties to affiliates		$ (197)
e.	**FAS 106 - OPEB**		
	To reflect revised rate year projection for FAS 106 OPEB expense		$ 9
f.	**FAS 87 - Pension**		
	To reflect revised rate year projection fpr FAS 87 Pension expense		$ 401
g.	**Combined Fringe Benefits Expense**		
(1)	Flow adjustment related to labor adjustment h(3) below.	(596)	
(2)	To reflect 3rd party and associated billing credits for fringe benefits, other than pension and OPEB's, per IR DAG-41	(173)	
(3)	Staff partial concession of g.(1)	290	
			$ (479)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
PSC Staff Direct Case
Staff Adjustments for the Rate Year Ending March 31, 2010
($000's)

h.	**Labor Expense**		
(1)	To disallow the non-VERO related portion of forecasted employee additions	$ (1,271)	
(2)	To limit management wage increases to inflation	(215)	
(3)	To base the RY forecast of the percentage of labor capitalized on year ending August 2008 actuals rather than year ending December 2007 actuals	(953)	
(4)	To transfer SIR labor costs from the SIR cost component to the labor cost component	194	
(5)	Staff partial concession of h.(1)	712	
(6)	Staff partial concession of h.(3)	477	
(7)	Correction of h.(4)	(122)	
			$ (1,178)
new	**Transportation**		
	To reflect updated cost of motor fuel		($268)
i.	**New Initiatives**		
	To eliminate Company's proposed marketing program		($1,040)
j.	**Productivity Adjustment**		
	Flow adjustment related to labor adjustments (h) above		$ 40
k.	**Site, Investigation & Remediation (SIR)**		
(1)	To transfer SIR labor costs from the SIR cost to the labor cost component	(194)	
(2)	Correction of k.(1)	122	
			$ (72)
l.	**Synergy Savings**		
(1)	To fully reflect expected savings from the NEG merger	$ (665)	
(2)	To reflect the Company's forecasted level of Key Span efficiency savings as "synergy savings" rather than being part of the Company's "productivity adjustment"	(600)	
(3)	To reflect Staff's forecasted level of Key Span efficiency savings (incremental to adjustment (ii) above)	(742)	$ (2,007)
m.	**Uncollectible Accounts**		
(1)	Reduce Uncollectible Expense based on Staff's 1.7% uncollectible rate	$ (871)	
(2)	Staff concession to 1.75%	436	
(3)	Change in uncollectibles due to change in commodity costs	(1,715)	
			$ (2,151)
	Total O&M Adjustment (Exhibit ___(AP-1), Schedule 2)		$ (9,828)
n.	**Company Correction & Update**		
	Correct Company Error (see footnote on Exhibit ___(PAL-1A))		$ 394
	Total Operating & Maintenance Expense Adjustments		$ (9,434)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
PSC Staff Direct Case
Staff Adjustments for the Rate Year Ending March 31, 2010
($000's)

Adj. 3 Amortization of Regulatory Deferrals

(a)	To reflect change in net regulatory deferrals amortization per Exhibit ___(AP-3)	$ (4,434)	
(b)	To eliminate doublecounted Pipeline 36 property tax adjustment	107	
(c)	To reflect customer service penalties per Company rebuttal	(179)	
(d)	To move CSS issue to CSS Deployment compliance filing	83	
(e)	Company Adj to amortize over 38 months vs. 32 ($14,707 vs. $17,464)	(2,757)	
			$ (7,180)

Adj. 4 Depreciation Expense

(a)	To reduce depreciation expense for costs allocable to affiliates using the Company's CSS	$ (24)	
(b)	To eliminate depreciation expense on forecasted plant additions related to inactive work orders of 6 months or more	(45)	
	To allocate to affiliates a portion of depreciation expense on the Company's hangar building and airplane	(32)	
(c)	To reflect Gas Safety Panel adjustment for Bare Steel H.P. inside sets	(36)	
(d)	To reflect Gas Rates Panel adjustment to remove Gas Marketing Program	(11)	
(e)	To reflect Rate Base Panel adjustment for removal and updates to common plant	(70)	
(f)	To reflect Staff's proposed depreciation rate changes	(2,618)	
(g)	Flow through adjustment related to Staff's plant in service concessions	20	
	Total Depreciation Expense Adjustments		$ (2,816)

Adj. 5 Taxes Other Than Revenue & Income Taxes

a.	**Real Estate Taxes**		
(1)	Reduce Property Taxes based on Staff's forecasting methodology	$ (2,599)	
(2)	Allow (1) at less inflated rate, but set up electric defered credit for same amount	2,487	
			$ (112)
b.	**Payroll Taxes**		
(1)	To match the percentage of total payroll taxes expensed to the percentage of total labor expensed		
	a. Service Company	$ (220)	
	b. NMPC	(34)	
(2)	Flow adjustment related to labor adjustment (h) above	(172)	
(3)	Staff payroll tax expense concessions	95	(331)
	Total Taxes Other Than Revenue & Income Taxes		$ (443)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
PSC Staff Direct Case
Staff Adjustments for the Rate Year Ending March 31, 2010
($000's)

Adj. 6	**Rate Base**		
a.	**Net Utility Plant**		
(1)	To eliminate forecasted plant additions related to inactive work orders of 6 months or more	$ (1,683)	
(2)	Update Gas Plant based on Staff's revised depreciation rates	1,300	
(3)	To reflect Gas Safety Panel adjustment for Bare Steel H.P. inside sets	(2,207)	
(4)	To reflect Gas Rates Panel adjustment to remove Gas Marketing Program	(680)	
(5)	To reflect Rate Base Panel adjustment for removal and updates to common plant	(3,434)	
(6)	Staff partial concession of adjustment a.(5)	1,525	
(7)	Staff concession for additional infrastructure enhancements	228	
			$ (4,951)
b.	**Regulatory Assets/Liabilities**		
(1)	To reflect change in net regulatory deferrals rate base balances per Exhibit ___(AP-3)	$ (6,644)	
(2)	To include Staff's forecast of deferred SIR costs in rate base	2,283	
(3)	Move CSS issue to CSS Deployment compliance filing	180	
(3)	Correction of doublecount on Pipeline 36 deferrals	235	
(3)	Reflect customer service penalties per Company rebuttal	(390)	
(4)	Company Adj. for extending Amort. Period to 38 months	(763)	
			$ (5,099)
c.	**Accumulated Deferred Federal Income Taxes**		
(1)	To reflect agreed upon errors in the Company's Corrections & Updates filing related to ADFIT	$ 3,299	
(2)	To reflect additional ADFIT related to deferred gas costs	(14,928)	$(11,629)
d.	To reflect additional ADSIT related to deferred gas costs		$ (3,504)
e.	Removal of inflation on forecasted M&S balance and usage of correct M&S balance		$ (1,400)
f.1	To adjust cash working capital allowance for tracking adjustment for staff's O&M expense adjustments.	$ (1,173)	
f.2	To adjust cash working capital allowance for tracking adjustment for Staff's concessions on O&M expense adjustments and to correct an error in Staff's direct case	263	
			$ (910)
g.	Increase EBCAP for the Company's forecasted increase in working capital related to its lead-lag study.		$ (1,343)
h.	Decrease gas in storage to reflect updated gas commodity costs		$(19,406)
	Total Rate Base Adjustments		$(48,242)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
Tax Deduction for Gas Interest Expense
For the Rate Year Ending March 31, 2010
($000's)

	Corrections & Updates Rate Year Ending March 31, 2010	Staff Adjustments	Rate Year Ending March 31, 2010
Avg Rate Base Per Books	1,118,187	(46,899)	1,071,288
Plus: Forecast of Avg Interest Bearing CWIP	14,288	0	14,288
Less: Rate Base moved to GAC	0	0	0
Less: Excess Earnings Adj (EBCAP)	40,693	1,343	42,036
Rate Base	1,091,782	(48,242)	1,043,540
Weighted Cost of LTD Debt	3.14%	0%	3.14%
Weighted Cost of Notes payable	0.05%	0%	0.05%
Weighted Cost of Gas Supplier Ref	0.00%	0%	0.00%
Weighted Cost of Cust Deposits	0.03%	0%	0.03%
subtotal weighted cost of debt	3.22%	0.00%	3.22%
Total Income Tax Interest Deduction	**$ 35,155**	**$ (1,553)**	**$ 33,602**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
Federal Income Taxes
For the Rate Year Ending March 31, 2010
($000's)

	Staff Adjusted Rate Case							
	Gas - As Adjusted Federal Taxable Income	Deferrable Basis	Book Taxable Income	@ the Statutory Rate	DFIT Reversals	Net FIT Before Rev Req	Rev Req @ Stat Rate	Net FIT After Rev Req
NET INCOME BEFORE FEDERAL & STATE INCOME TAXES	69,820,868		69,820,868	24,437,000		24,437,000	107,888,868	37,761,000
ADDITIONS								
PROVISION FOR DEPRECIATION	43,663,000	(2,816,000)	40,847,000	14,296,000		14,296,000		14,296,000
REAL ESTATE TAXES PER BOOKS	35,844,000		35,844,000	12,545,000		12,545,000		12,545,000
BUSINESS MEALS 50% DISALLOWANCE	118,460		118,460	41,000		41,000		41,000
DEDUCTIONS								
GAIN ON REDEMPTION BONDS	0		0	0		0		
OTHER POST RETIREMENT BENEFIT LIABILITY-MEDICARE PIECE	(4,462,000)		(4,462,000)	(1,562,000)	0	(1,562,000)		(1,562,000)
INTEREST	(35,155,000)	1,553,000	(33,602,000)	(11,761,000)		(11,761,000)		(11,761,000)
NEW YORK STATE INCOME TAXES - CURRENT PROVISION	(1,778,000)		(1,778,000)	(622,000)		(622,000)		(1,568,000)
OTHER STATE INCOME TAXES	0		0	0		0		0
COST OF REMOVAL	(3,520,600)	2,816,480	(704,120)	(246,000)	(1,018,000)	(1,264,000)		(1,264,000)
GAS CONTINGENCY RESERVE	(6,443,000)		(6,443,000)	(2,255,000)	1,303,000	(952,000)		(952,000)
TAX DEPRECIATION	(33,693,542)	2,816,000	(30,877,542)	(10,807,000)		(10,807,000)		(10,807,000)
REAL ESTATE TAXES FOR TAX	(35,844,000)		(35,844,000)	(12,545,000)		(12,545,000)		(12,545,000)
DIVIDENDS PAID ON CERTAIN PREF STOCK OF PUBLIC UTILITIES	(80,000)		(80,000)	(28,000)		(28,000)		(28,000)
TOTAL FIT EXPENSE	28,470,186	4,369,480	32,839,666	11,493,000	285,000	11,778,000		24,156,000

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 08-G-0609
State Income Taxes
For the Rate Year Ending March 31, 2010
($000's)

	Staff Adjusted Rate Case							
	Gas - As Adjusted							
	State Taxable Income	Deferrable Basis	Book Taxable Income	@ the Statutory Rate	DSIT Reversals	Net SIT Before Rev Req	Rev Req @ Stat Rate	Net SIT After Rev Req
NET INCOME BEFORE FEDERAL & STATE INCOME TAXES	69,820,868		69,820,868	4,957,000		4,957,000	107,888,868	7,660,000
ADDITIONS								
REAL ESTATE TAXES PER BOOKS	35,844,000		35,844,000	2,545,000		2,545,000		2,545,000
BUSINESS MEALS 50% DISALLOWANCE	118,460		118,460	8,000		8,000		8,000
DEDUCTIONS								
GAIN ON REDEMPTION BONDS	0		0	0		0		0
OTHER POST RETIREMENT BENEFIT LIABILITY-MEDICARE PIECE	(4,462,000)		(4,462,000)	(317,000)	0	(317,000)		(317,000)
INTEREST	(35,155,000)	1,553,000	(33,602,000)	(2,386,000)		(2,386,000)		(2,386,000)
GAS CONTINGENCY RESERVE	(6,443,000)		(6,443,000)	(457,000)	0	(457,000)		(457,000)
IBM CUSTOMER SYSTEM SETTLEMENT	(374,000)		(374,000)	(27,000)		(27,000)		(27,000)
REAL ESTATE TAXES FOR TAX	(35,844,000)		(35,844,000)	(2,545,000)		(2,545,000)		(2,545,000)
TOTAL SIT EXPENSE	23,505,328	1,553,000	25,058,328	1,778,000	0	1,778,000		4,481,000
	7.1%	eff Apr 2007						

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)

PSC Case No. 08-G-0609

Summary of Gas Deferral Account Forecast

Deferral Forecast at April 30, 2009

(Whole $)

		Gas Forecast April 30, 2009
REGULATORY ASSETS		
Pension Settlement Loss FY2003	182328	6,395,608
NY Sales Tax Audit Assmt (88-98) Gas	182518	184,583
SIR Expenditures Def-Gas	182537	4,332,145
OPEB Expense Deferred-Gas	182561	53,356,109
Pension Exp Deferred-Gas	182562	28,253,191
Incent Return on Ret Funding	182563	13,383,057
Total Regulatory Assets		105,904,691
		0
REGULATORY LIABILITIES		0
Medicare Act Tax Benefit Deferral	254325	14,106,439
Customer Service System (CSS)		0
Gas R&D Ventures Deferral	254351	323,245
NM - Gas Contingency Reserve	254514	25,998,272
NM - IBM Cust Sys Settlement Agreement	254515	1,089,715
NM - Loss on Sale of Building	254520	194,572
GRT Cust Refund 2000-Gas	254551	7,732,956
Bonus Depreciation Adjustment	254559	8,770,466
2006 Service Quality Penalty		479,379
NM - GRT Aud Refund (91-94)-Gas	254563	675,990
NM - KSE Merger Savings	TBA	(37,698)
Total Regulatory Liabilities		59,333,335
Net Regulatory Asset		46,571,356
Monthly Amortization based on 38 months		1,225,562
Annual Amortization		14,706,744
Annual (as stated in thousands)		**$ 14,707**

Niagara Mohawk (NiMo) Gas Depreciation - Average Service Lives & Net

Acct	Description	Average Service Life (yrs.)	Iowa Curve	Net Salvage %	Accrual Rate (%/yr.)
302.00	Franchises & Consents	10	SQ	0	10.000
	Transmission Plant				
365.00	Land Rights - Reg. Sta.	100	SQ	0	1.000
366.00	Str. & Imp	55	R2.0	-15	2.091
367.00	Main	80	R3.0	-20	1.500
369.15	Regulating Station Equip.	40	R0.5	-15	2.875
369.25	Regulating Station Equip.	40	R0.5	-15	2.875
369.55	M&R Sta. Equip - RTU	25	R5.0	-20	4.800
	Distribution Plant				
374.00	Land Rights	100	SQ	0	1.000
375.00	Str. & Imp	45	L0.0	0	2.222
376.11	Main - Steel	80	R3.0	-50	1.875
376.12	Main - Plastic	65	R4.0	-50	2.308
376.13	Main - Cast Iron	80	S0.5	-80	2.250
376.14	Main - Valves	80	R3.0	-20	1.500
378.10	M&R Sta Equip	40	L0.0	-5	2.625
378.20	M&R Sta Equip -	40	L0.1	-5	2.625
378.55	M&R Sta Equip-RTU	35	R5.0	-30	3.714
380.00	Services All	60	L1.0	-20	2.000
381.00	Meters	33	R2.5	0	3.030
382.00	Meter Installs	45	R1.0	-25	2.778
383.00	House Regs	40	R1.0	0	2.500
384.00	House Regs Install	40	R4.0	0	2.500
385.00	Ind. Measuring & Reg Sta. Equip	25	R5.0	0	4.000
	General Plant				
390.00	Structures & Improvements	55	L0.5	0	1.818
391.10	Office Furniture	22	SQ	0	4.545
391.15	Data Processing Equip	5	SQ	0	20.000
393.00	Stores Equip	22	SQ	0	4.545
394.10	Tools & Work Equip	22	SQ	0	4.545
394.20	Nat. Gas Refueling Sta. Equip	22	SQ	0	4.545
395.00	Lab Equip	22	SQ	0	4.545
396.00	Power Operated Equip	22	SQ	0	4.545
397.10	Comm. Equip - Network	22	SQ	0	4.545
397.20	Comm. Equip - Radio	22	SQ	0	4.545
397.30	Comm. Equip - Telephone	8	SQ	0	12.500
398.00	Misc. Equip	22	SQ	0	4.545
398.10	Misc. Equip	22	SQ	0	4.545

Case 08-G-0609

Current Rates

Section 2.1 (f)

APPENDIX D

04/01/2009-03/31/2010

Summary Class

	# Customer Months	Throughput (Therms)	Customer Margin	Misc Rev: Not Merchant Function	Misc Rev: Merchant Function	Total Misc Rev	Total Delivery Rev	Total Commodity Rev	Total GRT Rev	Total Revenue
SC1 Res Non Heat	385,100	11,817,109	$7,991,624	$5,419	$262,576	$267,995	$8,259,619	$9,857,242	$267,808	$18,384,670
SC1 Res Heat	4,874,919	411,829,475	$138,959,270	$188,912	$9,150,851	$9,339,763	$148,299,033	$347,123,383	$5,699,422	$501,121,837
SC2 Res Non Heat	998	113,527	$44,568	$52	$2,523	$2,575	$47,143	$94,929	$821	$142,893
SC2 Res Heat	7,010	1,468,596	$440,318	$674	$32,632	$33,306	$473,624	$1,235,147	$9,877	$1,718,648
SC2 Comm Non Heat	21,853	3,010,169	$1,039,855	$-2,347	$66,886	$64,539	$1,104,394	$2,486,444	$20,755	$3,611,593
SC2 Comm Heat	342,116	112,417,476	$27,192,020	$-75,729	$2,497,916	$2,422,188	$29,614,207	$94,711,221	$718,601	$125,044,029
SC2 Industrial	1,574	2,018,232	$305,380	$-13,418	$44,845	$31,427	$336,807	$1,620,708	$11,314	$1,968,829
SC3 Comm Non Heat	24	547,342	$38,550	$13,548	$0	$13,548	$52,098	$437,013	$2,827	$491,938
SC3 Comm Heat	291	2,197,577	$274,756	$23,296	$0	$23,296	$298,052	$1,773,041	$11,971	$2,083,065
SC3 Industrial	84	1,360,272	$106,647	$59,166	$0	$59,166	$165,813	$1,073,502	$7,163	$1,246,478
SC4 Com Heat	24	6,952,133	$603,137	$0	$0	$0	$603,137	$6,554,653	$41,372	$7,199,162
SC6 Interruptible	276	100,773,724	$4,764,820	$0	$0	$0	$4,764,820	$0	$0	$4,764,820
SC5 Firm	1,908	65,965,987	$4,103,250	$-16,732	$0	$-16,732	$4,086,518	$0	$0	$4,086,518
SC7 Firm	7,920	57,104,811	$6,908,753	$12,672	$0	$12,672	$6,921,425	$0	$0	$6,921,425
SC9 Special Contracts	108	277,613,715	$11,380,294	$0	$0	$0	$11,380,294	$0	$126,573	$11,506,867
NYSEG Transp	12	2,833,980	$231,608	$0	$0	$0	$231,608	$0	$0	$231,608
SC8 Firm and Standby	649	138,585,127	$7,159,562	$20,041	$0	$20,041	$7,179,603	$19,490,095	$0	$26,669,698
SC10 NGV	12	2,316	$1,275	$0	$0	$0	$1,275	$2,114	$20	$3,409
SC1 MB RES Non Heat	50,419	2,199,810	$1,156,528	$1,009	$0	$1,009	$1,157,537	$0	$23,601	$1,181,138
SC1 MB RES Heat	1,086,184	103,747,207	$32,373,105	$47,592	$0	$47,592	$32,420,697	$0	$660,670	$33,081,367
SC2 MB RES Non Heat	158	10,694	$5,437	$5	$0	$5	$5,441	$0	$0	$5,441
SC2 MB RES Heat	2,811	1,094,583	$273,575	$502	$0	$502	$274,077	$0	$0	$274,077
SC2 MB COM Non Heat	7,412	3,623,040	$823,950	$856	$0	$856	$824,807	$0	$0	$824,807
SC2 MB COM Heat	152,709	84,773,447	$18,175,165	$-27,448	$0	$-27,448	$18,147,717	$0	$0	$18,147,717
SC2 MB Industrial	553	1,315,652	$187,211	$-5,494	$0	$-5,494	$181,716	$0	$0	$181,716
SC12 DG < 250K	12	252,552	$12,842	$116	$5,612	$5,727	$18,570	$193,077	$1,223	$212,869
Summary Class subtotal:	**6,945,136**	**1,393,628,553**	**264,553,500**	**232,691**	**12,063,841**	**12,296,532**	**276,850,032**	**486,652,567**	**7,604,018**	**771,106,618**

Other Gas Revenue

	# Customer Months	Throughput (Therms)	Customer Margin	Misc Rev: Not Merchant Function	Misc Rev: Merchant Function	Total Misc Rev	Total Delivery Rev	Total Commodity Rev	Total GRT Rev	Total Revenue
Late Payment Charge	0	0	$3,232,653	$0	$0	$0	$3,232,653	$0	$46,575	$3,279,228
Bal Service Cost	0	0	$345,968	$0	$0	$0	$345,968	$0	$0	$345,968
Misc Gas Revenue	0	0	$90,048	$0	$0	$0	$90,048	$0	$0	$90,048
Reestablishment Charge	0	0	$52,490	$0	$0	$0	$52,490	$0	$0	$52,490
Research & Development	0	0	$-451,198	$0	$0	$0	$-451,198	$0	$0	$-451,198
Supervision & Admin Allocated t	0	0	$861,816	$0	$0	$0	$861,816	$0	$0	$861,816
Other Gas Revenue subtotal:	**0**	**0**	**$4,131,777**	**$0**	**$0**	**$0**	**$4,131,777**	**$0**	**$46,575**	**$4,178,352**
Grand Total All Revenue:	**6,945,136**	**1,393,628,553**	**$268,685,277**	**$232,691**	**$12,063,841**	**$12,296,532**	**$280,981,809**	**$486,652,567**	**$7,650,594**	**$775,284,970**

Section 2.2.1

Rev Req with 38 mos Amort

Rate Design based on
Revenue Allocation
reflecting Mains classified
35% Customer/65% Demand
Settlement Thruput Forecast

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF PROPOSED GAS REVENUE REQUIREMENT
COMPARISON OF PRESENT AND PROPOSED REVENUES
Based on Twelve Months Ended March 31, 2010

Line	Description	Service Class Number	Average Number of Customers	Annual Sales/Deliveries therms	Total Present Revenues at Current rates	Total Proposed Revenues	Increase	Percent Increase	Percent Increase Net of Fuel	Ratio to Average	Number of Customers Increased	Decreased	Unchanged
1	Residential Commodity Service & Aggregation Service	1	533,052	529,593,603	$553,769,012	$583,479,733	$29,710,721	5.37%	15.10%	1.11	533,052	0	0
2	Small General Commodity Service & Aggregation Service	2	44,766	209,845,417	$151,919,749	$158,325,829	$6,406,080	4.22%	12.37%	0.91	44,766	0	0
3	Large General Service	3	33	4,105,191	$3,821,481	$3,847,289	$25,808	0.68%	4.80%	0.35	33	0	0
4	Interruptible Large Volume	4	2	6,952,133	$7,199,162	$7,213,559	$14,397	0.20%	2.23%	0.16	2	0	0
5	Firm 250,000 to 1,000,000 Therms	5	159	65,965,987	$4,086,518	$4,775,979	$689,462	16.87%	16.87%	1.24	159	0	0
6	Interruptible >2,500,000 Therms	6	23	100,773,724	$4,764,820	$4,828,479	$63,659	1.34%	1.34%	0.10	23	0	0
7	Firm Small > 50,000 to 250,000 Therms	7	660	57,104,811	$6,921,425	$7,957,318	$1,035,893	14.97%	14.97%	1.10	660	0	0
8	Large Firm > 1,000,000 Therms	8	54	138,585,127	$26,669,698	$27,873,202	$1,203,503	4.51%	16.76%	1.23	54	0	0
9	NYSEG Transportation		1	2,833,980	$231,608	$272,393	$40,785	17.61%	17.61%	1.29	1	0	0
10	Individually Negotiated Transportation Service	9	9	277,613,715	$11,506,867	$11,506,867	$0	0.00%	0.00%	0.00	0	0	9
11	Natural Gas Vehicles	10	1	2,316	$3,409	$3,409	$0	0.00%	0.00%	0.00	0	0	1
12	Distributed Generation Service - Non Residential	12	1	252,552	$212,869	$214,809	$1,940	0.91%	9.80%	0.72	1	0	0
13	Delivery Service for Dual Fuel Electric Generators	14	0	0	$0	$0	$0	0.00%	0.00%	0.00	0	0	0
14	Subtotal		578,761	1,393,628,556	$771,106,618	$810,298,866	$39,192,248	5.08%	13.78%	1.01	578,751	0	10
15	Other Misc Gas Revenues				$4,178,352	$4,399,879	$221,527	5.30%	5.30%	0.39	0	0	0
16	TOTAL		578,761	1,393,628,556	$775,284,970	$814,698,745	$39,413,775	5.08%	13.66%	1.00	578,751	0	10

Note: Revenue Allocation reflects Company methodology as provided in Response to MI-4 Q17 Part ii modified to reflect inclusion of existing MFC revenue in development of allocation of increase
Note: - Revenue Requirement reflects allocation of $39.428 million based on a 38 amort amortization of regulatory assets
Note: Rate Design Reflects Settlement thruput forecast

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PROPOSED GAS RATE DESIGN
SUMMARY OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010

Proposed rates based on the Allocation of Incremental Revenue Mains classified 35% customer / 65% demand- Reflects Settlement Thruput Forecast

				Revenue Increase	Percent Net of Fuel
				$38,796,122	14.61%
		(1)	(2)	(3)	(4)
		Current Rates	05/20/09 Rates	Increase	%
SC 1 Cust	+ 3 therms	$14.71	$17.45	$2.74	18.63%
	+ 3 therms (Low Income)	$14.71	$9.95	($4.76)	-32.36%
	next 47 thm	$0.34921	$0.38728	$0.03807	10.90%
	over 50	$0.05322	$0.05902	$0.00580	10.90%
	Merchant Function Charge	$0.02222	$0.03794	$0.01572	70.75%
SC 2 Customer	+ 3 thm	$19.35	$23.65	$4.30	22.22%
	next 277	$0.26966	$0.29945	$0.02979	11.05%
	next 4720	$0.15686	$0.17419	$0.01733	11.05%
	over 5,000	$0.05028	$0.05584	$0.00556	11.06%
	Merchant Function Charge	$0.02222	$0.02109	($0.00113)	-5.09%
	Merchant Function Charge SC2 Ind	$0.02222	$0.02097	($0.00125)	-5.63%
SC 3 Customer	Incl 5000 therms	$782.11	$782.76	$0.65	0.08%
	over 5000 thm	$0.04627	$0.10172	$0.05545	119.84%
SC 4	Facilities Charge	$300.00	$896.43	$596.43	198.81%
	margin	VARIABLE	VARIABLE	$0.00000	0.00%
SC 5 Firm	Admin Charge	$353.85	$465.92	$112.07	31.67%
	all thm in excess of 100	$0.05211	$0.05934	$0.00723	13.87%
SC 6 Interruptible	admin charge	$350.00	$580.65	$230.65	65.90%
	all thm in excess of 100	VARIABLE	VARIABLE	$0.00000	0.00%
SC 7	First 2,100 thm (present)	$303.30	$350.95	$47.65	15.71%
	excess 2100 therms	$0.10334	$0.11844	$0.01510	14.61%
SC 8	First 100 Therms or less	$707.70	$825.65	$117.95	16.67%
	Next 99,900 therms per therm	$0.05211	$0.05934	$0.00723	13.87%
	Next 400,000 therms per therm	$0.04717	$0.05613	$0.00896	19.00%
	Over 500,000 therms per therm	$0.04044	$0.04842	$0.00798	19.73%
	Include 100 thm				
NYSEG	Customer	$808.80	$809.45	$0.65	0.08%
	Demand per peak day demand	$0.11627	$0.47500	$0.35873	308.53%
	Volumetric	$0.07077	$0.03235	($0.03842)	-54.29%
	Over 2,300,000 per Year	$0.03235	$0.03235	$0.00000	0.00%
Natural Gas Vehicles	Customer				
	Commodity all therms	0.10500	0.10500	$0.00000	0.00%
SC 1MB	+ 3 therms	$14.71	$17.45	$2.74	18.63%
	next 47 thm	$0.34921	$0.38728	$0.03807	10.90%
	over 50	$0.05322	$0.05902	$0.00580	10.90%
SC 2 Monthly Balancing	+ 3 thm	$19.35	$23.65	$4.30	22.22%
	next 277	$0.26966	$0.29945	$0.02979	11.05%
	next 4720	$0.15686	$0.17419	$0.01733	11.05%
	over 5,000	$0.05028	$0.05584	$0.00556	11.06%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PROPOSED GAS RATE DESIGN
SUMMARY OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010

Proposed rates based on the Allocation of Incremental Revenue Mains classified 35% customer / 65% demand- Reflects Settlement Thruput Forecast

		(1) Current Rates	(2) 05/20/09 Rates	(3) Increase	(4) %
SC12 DG < 250K	+ 3 thm	$100.00	$147.65	$47.65	47.65%
	over 3 Therms (Apr - Oct)	$0.04149	$0.04755	$0.00606	14.61%
	over 3 Therms (Nov - Mar)	$0.05256	$0.06024	$0.00768	14.61%
	Merchant Function Charge	$0.02222	$0.02086	($0.00136)	-6.12%
SC12 DG > 250K < 1 Million	+ 3 thm	$353.85	$465.92	$112.07	31.67%
	over 3 Therms (Apr - Oct)	$0.03697	$0.04237	$0.00540	14.61%
	over 3 Therms (Nov - Mar)	$0.04683	$0.05367	$0.00684	14.61%
	Merchant Function Charge	$0.02222	$0.02086	($0.00136)	-6.12%
SC12 DG > 1 Million < 2.5 Million	+ 100 thm	$1,400.00	$1,400.65	$0.65	0.05%
	next 499,900 Therms (Apr - Oct)	$0.03447	$0.03951	$0.00504	14.62%
	next 499,900 Therms (Nov - Mar)	$0.04366	$0.05004	$0.00638	14.61%
	over 500,000 (Apr - Oct)	$0.02955	$0.03387	$0.00432	14.62%
	over 500,000 (Nov - Mar)	$0.03743	$0.04290	$0.00547	14.61%
	Merchant Function Charge	$0.02222	$0.02086	($0.00136)	-6.12%
SC12 DG > 2.5 Million	+ 3 thm	$1,400.00	$1,400.65	$0.65	0.05%
	over 3 Therms (Apr - Oct)	$0.00691	$0.00792	$0.00101	14.62%
	over 3 Therms (Nov - Mar)	$0.00876	$0.01004	$0.00128	14.61%
	Demand Chg Per Therm of MPDQ	$0.75500	$0.86534	$0.11034	14.61%
	Merchant Function Charge	$0.02222	$0.02086	($0.00136)	-6.12%
SC13 DG	+ 3 thm	$24.00	$26.94	$2.94	12.25%
	over 3 Therms	$0.03200	$0.03668	$0.00468	14.63%
	Merchant Function Charge	$0.02222	$0.02098	($0.00124)	-5.58%

Section 2.2.1
Settlement Forecast
Mains 35_65
Sheet 1 of 18

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 1-Residential non heat
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	348,980	$14.71	$5,133,496	$17.45	$6,089,701	$956,205	18.63%
Low Income Bills	36,120	$14.71	$531,325	$9.95	$359,394	($171,931)	-32.36%
Subtotal Bills	385,100		$5,664,821		$6,449,095	$784,274	
0 - 3 therms	1,000,395	-					
4 - 50 therms per therm	5,916,206	$0.34921	$2,065,998	$0.38728	$2,291,228	$225,230	10.90%
Over 50 therms per therm	4,900,508	$0.05322	$260,805	$0.05902	$289,228	$28,423	10.90%
Energy Revenue	11,817,109		$2,326,803		$2,580,456	$253,653	10.90%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue			$2,326,803		$2,580,456	$253,653	10.90%
Total Delivery Revenue	11,817,109		$7,991,624		$9,029,551	$1,037,927	12.99%
MCG Revenue			$9,857,242		$9,857,242	$0	0.00%
Merchant Function Charge		$0.02222	$262,576	$0.03794	$448,341	$185,765	70.75%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$5,419	$0.00046	$5,419	$0	0.00%
Subtotal before GRT			$18,116,861		$19,340,553	$1,223,692	6.75%
Delivery GRT		2.0408%	$163,093	2.0408%	$184,386	$21,293	13.06%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5780%	$104,716	0.5780%	$111,789	$7,073	6.75%
TOTAL REVENUE			$18,384,670		$19,636,728	$1,252,057	6.81%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 1-Residential heat
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	4,417,659	$14.71000	$64,983,764	$17.45000	$77,088,150	$12,104,386	18.63%
Low Income Bills	457,260	$14.71	$6,726,295	$9.95	$4,549,737	($2,176,558)	-32.36%
Subtotal Bills	4,874,919		$71,710,058		$81,637,887	$9,927,828	
0 - 3 therms	14,167,516	-					
4 - 50 therms per therm	155,699,997	$0.34921	$54,371,996	$0.38728	$60,299,495	$5,927,499	10.90%
Over 50 therms per therm	241,961,962	$0.05322	$12,877,216	$0.05902	$14,280,595	$1,403,379	10.90%
Energy Revenue	411,829,475		$67,249,212		$74,580,090	$7,330,878	10.90%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue			$67,249,212		$74,580,090	$7,330,878	10.90%
Total Billed Delivery Revenue	411,829,475		$138,959,270		$156,217,976	$17,258,706	12.42%
MCG Revenue w/o GRT			$347,123,383		$347,123,383	$0	0.00%
Merchant Function Charge		$0.02222	$9,150,851	$0.03794	$15,624,810	$6,473,959	70.75%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$188,912	$0.00046	$188,912	$0	0.00%
Subtotal before GRT			$495,422,416		$519,155,082	$23,732,666	4.79%
Delivery GRT		2.0408%	$2,835,880	2.0408%	$3,191,951	$356,071	12.56%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5780%	$2,863,541	0.5780%	$3,000,716	$137,175	4.79%
TOTAL REVENUE			$501,121,837		$525,347,748	$24,225,911	4.83%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219- SC 2-Residential and Small Commercial
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	371,977	$19.35000	$7,197,755	$23.65	$8,797,256	$1,599,501	22.22%
Adjustment Factor			1.00000				
Bills Adjusted	371,977	$19.35000	$7,197,755		$8,797,256	$1,599,501	22.22%
0 - 3 therms	959,664						
Next 277 therms per therm	41,591,377	$0.26966	$11,215,531	$0.29945	$12,454,538	$1,239,007	11.05%
Next 4720 therms per therm	61,547,112	$0.15686	$9,654,280	$0.17419	$10,720,891	$1,066,611	11.05%
Over 5,000 therms per therm	12,911,615	$0.05028	$649,196	$0.05584	$720,985	$71,789	11.06%
Economic Development Discount			($131,024)		($131,024)	$0	0.00%
Energy Revenue	117,009,768		$21,387,983		$23,765,390	$2,377,407	11.12%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	117,009,768		$21,387,983		$23,765,390	$2,377,407	11.12%
Total Billed Delivery Revenue			$28,585,738		$32,562,646	$3,976,908	13.91%
MCG Revenue w/o GRT			$98,527,741		$98,527,741	$0	0.00%
Merchant Function Charge		$0.02222	$2,599,957	$0.02109	$2,467,736	($132,221)	-5.09%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$53,673	$0.00046	$53,673	$0	0.00%
Subtotal			$129,767,109		$133,611,796	$3,844,687	2.96%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5780%	$750,054	0.5780%	$772,276	$22,222	2.96%
TOTAL REVENUE			$130,517,163		$134,384,072	$3,866,910	2.96%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 2-Industrial
RATE DESIGN

		Current Rates		Proposed Rates			
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Percent Increase
Bills	1,574	$19.35000	$30,457	$23.65	$37,225	$6,768	22.22%
Adjustment Factor			1.00000				
Bills Adjusted	1,574	$19.35000	$30,457		$37,225	$6,768	22.22%
0 - 3 therms	4,530						
Next 277 therms per therm	267,078	$0.26966	$72,020	$0.29945	$79,976	$7,956	11.05%
Next 4720 therms per therm	1,079,779	$0.15686	$169,374	$0.17419	$188,087	$18,713	11.05%
Over 5,000 therms per therm	666,846	$0.05028	$33,529	$0.05584	$37,237	$3,708	11.06%
Economic Development Discount			($14,343)		($14,343)	$0	0.00%
Energy Revenue	2,018,232		$260,580		$290,957	$30,376	11.66%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	2,018,232		$260,580		$290,957	$30,376	11.66%
Total Billed Delivery Revenue			$291,037		$328,182	$37,145	12.76%
MCG Revenue w/o GRT			$1,620,708		$1,620,708	$0	0.00%
Merchant Function Charge		$0.02222	$44,845	$0.02097	$42,322	($2,523)	-5.63%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$924	$0.00046	$924	$0	0.00%
Subtotal			$1,957,514		$1,992,136	$34,622	1.77%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5780%	$11,315	0.5780%	$11,515	$200	1.77%
TOTAL REVENUE			$1,968,829		$2,003,651	$34,822	1.77%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 3
RATE DESIGN

	Bills/therms	Current Rates Rate	Current Rates Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase	Percent Increase
Bills	399	$782.11	$312,062	$782.76	$312,321	$259	0.08%
Adjustment Factor			1.00000		same		
Bills Adjusted	399	$782.11	$312,062		$312,321	$259	0.08%
0 - 5000 therms	1,888,951	$0.00	0	$0.00000	0	$0	0.00%
over 5000 therms per therm	2,331,788	$0.04627	$107,892	$0.10172	$237,189	$129,298	119.84%
Margin Recovered in Commodity Ratchet			$103,897		$0	($103,897)	-100.00%
Economic Development Discount			($9,770)		($9,770)	$0	0.00%
Energy Revenue	4,220,739		$202,019		$227,419	$25,401	12.57%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	4,220,739		$202,019		$227,419	$25,401	12.57%
Metered throughput	4,105,191						
Total Billed Delivery Revenue			$514,081		$539,741	$25,660	4.99%
MCG Revenue w/o GRT			$3,283,556		$3,283,556	$0	0.00%
Merchant Function Charge		n/a	$0	n/a	$0	$0	0.00%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00045	$1,882	$0.00045	$1,882	$0	0.00%
Subtotal			$3,799,519		$3,825,179	$25,660	0.68%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5780%	$21,962	0.5780%	$22,110	$148	0.68%
TOTAL REVENUE			$3,821,481		$3,847,289	$25,808	0.68%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 4 (Grandfathered Service)
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	24	$300.00000	$7,200	$896.43	$21,514	$14,314	198.81%
all therms margin	6,952,133	$0.08572	$595,937	$0.08572	$595,937	$0	0.00%
subtotal	6,952,133		$595,937		$595,937	$0	0.00%
Cost of Gas	6,952,133	0.94283	$6,554,653		$6,554,653	$0	0.00%
Subtotal			$7,157,790		$7,172,104	$14,314	0.20%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5780%	$41,372	0.5780%	$41,455	$83	0.20%
Total Revenue			$7,199,162		$7,213,559	$14,397	0.20%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 7
RATE DESIGN

		Current Rates		Proposed Rates			
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Percent Increase
Bills	7920	$303.30000	$2,402,136	$350.95	$2,779,524	$377,388	15.71%
First 2100 Therms per Therm	13,495,206	$0.00000	0	$0.00000	$0	$0	0.00%
Over 2100 Therms per Therm	43,609,605	$0.10334	$4,506,617	$ 0.11844	$5,165,122	$658,505	14.61%
Economic Development Discount			($13,516)		($13,516)	$0	0.00%
Energy Revenue	57,104,811		4,493,101		$5,151,606	$658,505	14.66%
Adjustment Factor	1.0000		1.0000		1.0000		
TOTAL Billed Delivery Revenue	57,104,811		$6,895,237		$7,931,130	$1,035,893	15.02%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$26,188	$0.00046	$26,188	$0	0.00%
Standby Charges			$0		$0	$0	0.00%
Subtotal			$6,921,425		$7,957,318	$1,035,893	14.97%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Total Revenue			$6,921,425		$7,957,318	$1,035,893	14.97%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219- SC 5
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
FIRM SERVICE - SC5							
Bills	1908	$353.850	$675,146	$465.92	$888,975	$213,830	31.67%
First 100 thms	180,076	$0.00000	$0	$0.00000	0	$0	0.00%
Over 100 Therms per therm	65,785,911	$0.05211	$3,428,104	$0.05934	$3,903,736	$475,632	13.87%
Economic Development	$0		($46,953)		($46,953)	$0	0.00%
Energy Revenue	65,965,987		3,381,151		3,856,783	$475,632	14.07%
Adjustment Factor	1.0000		1.0000		1.0000		
TOTAL Billed Delivery Revenue	65,965,987		$4,056,297		$4,745,758	$689,462	17.00%
SBC		0	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$30,221	$0.00046	$30,221	$0	0.00%
Standby Charges			$0		$0	$0	0.00%
Subtotal			$4,086,518		$4,775,979	$689,462	16.87%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		N/A	$0	N/A	$0	$0	0.00%
Total Revenues			$4,086,518		$4,775,979	$689,462	16.87%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219- SC 6
RATE DESIGN

		Current Rates		Proposed Rates			
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Percent Increase
INTERRUPTIBLE SERVICE - SC6							
Bills	276	$350.00000	$96,600	$580.65	$160,259	$63,659	65.90%
First 100 thms	30,232	$0.00000	$0	$0.00000	0	$0	0.00%
Over 100 Therms per therm	100,743,492	$0.04634	$4,668,220	$0.04634	$4,668,220	$0	0.00%
Energy Revenue	100,773,724		$4,668,220		$4,668,220	$0	0.00%
Adjustment Factor	1.0000		1.0000		1.0000		
TOTAL Billed Delivery Revenue	100,773,724		$4,764,820		$4,828,479	$63,659	1.34%
Misc Rev (R&D)		$0.00000	$0	$0.00000	$0	$0	0.00%
Standby Charges			$0		$0	$0	0.00%
Subtotal			$4,764,820		$4,828,479	$63,659	1.34%
							0.00%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Total Revenues			$4,764,820		$4,828,479	$63,659	1.34%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Energy Revenue
PSC NO. 219- SC 9
RATE DESIGN

	Bills/therms	Current Rates Rate	Revenue	Proposed Rates Rate	Revenue	Increase	Percent Increase
SPECIAL CONTRACTS - SC9							
Bills	108						
Delivery Revenue			$11,380,294		$11,380,294	$0	0.00%
Energy Revenue	277,613,715		$11,380,294		$11,380,294	$0	0.00%
Adjustment Factor	1.00000		1.0000		1.0000		
TOTAL Billed Delivery Revenue	277,613,715		$11,380,294		$11,380,294	$0	0.00%
Misc. Rev (R&D)		$0.00000	$0	$0.00000	$0	$0	0.00%
Standby Charges			$0		$0	$0	0.00%
Subtotal			$11,380,294		$11,380,294	$0	0.00%
							0.00%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Snit recovered via GRT rate			$126,573		$126,573	$0	0.00%
Total Revenues			$11,506,867		$11,506,867	$0	0.00%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
NYSEG
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/Therm	Rate	Revenue	Rate	Revenue	Increase	Increase
NYSEG TRANSPORTATION SERVICE							
Customer	12	$ 808.80	$9,706	$809.45	$9,713	$8	0.08%
Demand	360,000	$ 0.11627	$41,857	$ 0.47500	$171,000	$129,143	308.53%
First 2,300,000 per year	2,300,000	$0.07077	$162,771	$ 0.03235	$74,405	($88,366)	-54.29%
Over 2,300,000 therms per year	533,980	$0.07077	$37,790	$0.03235	$17,274	($20,516)	-54.29%
Reconciliation of Volumetric Charge	533,980	($0.03842)	($20,516)	$0.00000	$0	$20,516	-100.00%
Total Therms	2,833,980		$231,608		$272,393	$40,785	17.61%
Surcharge			$0		$0	$0	0.00%
GRT at	0.0000%		$0		$0	$0	0.00%
TOTAL REVENUE for Transportation Service	1.0000		$231,608		$272,393	$40,785	17.61%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 8
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
FIRM SERVICE - SC8							
Bills	649	$707.700	$459,297	$825.650	$535,847	$76,550	16.67%
0-100 Therms	63,682	$0.00000	$0	$0.00000	$0	$0	0.00%
Next 99,900 therms per therm	56,505,233	$0.05211	$2,944,488	$0.05934	$3,353,021	$408,533	13.87%
Next 400,000 therms per therm	65,236,388	$0.04717	$3,077,200	$0.05613	$3,661,718	$584,518	19.00%
Over 500,000 therms per therm	16,779,824	$0.04044	$678,576	$0.04842	$812,479	$133,903	19.73%
Economic Development			($43,450)		($43,450)	$0	0.00%
Energy Revenue	138,585,127		$6,656,814		$7,783,768	$1,203,503	18.08%
Adjustment Factor	1.00000		1.00000		1.00000		
TOTAL Billed Delivery Revenue	138,585,127		7,116,111		$8,319,615	$1,203,503	16.91%
SBC		$0.0000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$63,492	$0.00046	$63,492	$0	0.00%
Standby Commodity Charges			$18,990,199		$18,990,199	$0	0.00%
Standby Demand Charges			$499,896		$499,896	$0	0.00%
Subtotal			$26,669,698		$27,873,202	$1,203,503	4.51%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Total Revenues			$26,669,698		$27,873,202	$1,203,503	4.51%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 10 NGV
RATE DESIGN

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		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	12	$0.00000	$0	$0.00000	$0	$0	0.00%
all therms margin	2,316	$0.54922	$1,272	$0.54922	$1,272	$0	0.00%
Energy Revenue	2,316		$1,272		$1,272	$0	0.00%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	2,316		$1,272		$1,272	$0	0.00%
Total Billed Delivery Revenue			$1,272		$1,272	$0	0.00%
Commodity Revenue			$2,114		$2,114	$0	0.00%
Subtotal			$3,386		$3,386	$0	0.00%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.6793%	$23	0.6793%	$23	$0	0.00%
TOTAL REVENUE			$3,409		$3,409	$0	0.00%

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 1-Residential Non Heat Monthly Balancing
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	45,679	$14.71000	$671,938	$17.45	$797,099	$125,160	18.63%
Low Income Bills	4,740	$14.71	$69,725	$9.95	$47,163	($22,562)	-32.36%
Subtotal Bills	50,419		$741,663		$844,262	$102,598	
0 - 3 therms	140,145	-					
4 - 50 therms per therm	1,031,283	$0.34921	$360,134	$0.38728	$399,395	$39,261	10.90%
Over 50 therms per therm	1,028,383	$0.05322	$54,731	$0.05902	$60,695	$5,965	10.90%
Energy Revenue	2,199,811		$414,865		$460,090	$45,226	10.90%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	2,199,811		$414,865		$460,090	$45,226	10.90%
Total Delivery Revenue			$1,156,528		$1,304,352	$147,824	12.78%
SBC		$0	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$1,009	$0.00046	$1,009	$0	0.00%
Subtotal before GRT			$1,157,537		$1,305,361	$147,824	12.77%
Delivery GRT		2.0407%	$23,601	2.0407%	$26,638	$3,037	12.87%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
TOTAL REVENUE			$1,181,138		$1,331,999	$150,861	12.77%

Section 2.2.1
Settlement Forecast
Mains 35_65
Sheet 15 of 18

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 1-Residential Heat Monthly Balancing
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	984,304	$14.71000	$14,479,112	$17.45	$17,176,105	$2,696,993	18.63%
Low Income Bills	101,880	$14.71	$1,498,655	$9.95	$1,013,706	($484,949)	-32.36%
Subtotal Bills	1,086,184		$15,977,767		$18,189,811	$2,212,044	
0 - 3 therms	3,221,780	-					
4 - 50 therms per therm	37,316,716	$0.34921	$13,031,370	$0.38728	$14,452,018	$1,420,647	10.90%
Over 50 therms per therm	63,208,712	$0.05322	$3,363,968	$0.05902	$3,730,578	$366,611	10.90%
Energy Revenue	103,747,208		$16,395,338		$18,182,596	$1,787,258	10.90%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue			$16,395,338		$18,182,596	$1,787,258	10.90%
Total Delivery Revenue	103,747,208		$32,373,105		$36,372,407	$3,999,302	12.35%
SBC		$0	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$47,592	$0.00046	$47,592	$0	0.00%
Subtotal before GRT			$32,420,697		$36,419,999	$3,999,302	12.34%
Delivery GRT		2.0408%	$660,670	2.0408%	$743,259	$82,589	12.50%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
TOTAL REVENUE			$33,081,367		$37,163,258	$4,081,891	12.34%

Section 2.2.1
Settlement Forecast
Mains 35_65
Sheet 16 of 18

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219- SC 2-Residential and Small Commercial Monthly Balancing
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	163,090	$19.35000	$3,155,792	$23.65	$3,857,079	$701,287	22.22%
Adjustment Factor			1.00000				
Bills Adjusted	163,090	$19.35000	$3,155,792	$ 23.65	$3,857,079	$701,287	22.22%
0 - 3 thm	444,214						
Next 277 therms per therm	24,243,937	$0.26966	$6,537,620	$0.29945	$7,259,847	$722,227	11.05%
Next 4720 therms per therm	59,353,420	$0.15686	$9,310,177	$0.17419	$10,338,772	$1,028,595	11.05%
Over 5,000 therms per therm	5,460,194	$0.05028	$274,539	$0.05584	$304,897	$30,359	11.06%
Economic Development Discount			($67,137)		($67,137)	$0	0.00%
Energy Revenue	89,501,765		$16,055,199		$17,836,379	$1,781,180	11.09%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	89,501,765		$16,055,199		$17,836,379	$1,781,180	11.09%
Total Delivery Revenue			$19,210,991		$21,693,458	$2,482,467	12.92%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$41,051	$0.00046	$41,051	$0	0.00%
Subtotal before GRT			$19,252,042		$21,734,509	$2,482,467	12.89%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
TOTAL REVENUE			$19,252,042		$21,734,509	$2,482,467	12.89%

Section 2.2.1
Settlement Forecast
Mains 35_65
Sheet 17 of 18

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219 - SC 2-Industrial Monthly Balancing
RATE DESIGN

	Bills/therms	Current Rates Rate	Current Rates Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase	Percent Increase
Bills	553	$19.35000	$10,701	$23.65	$13,078	$2,378	22.22%
Adjustment Factor			1.00000				
Bills Adjusted	553	$19.35000	$10,701	$23.65	$13,078	$2,378	22.22%
0 - 3 thm	3,205						
Next 277 therms per therm	172,757	$0.26966	$46,586	$0.29945	$51,732	$5,146	11.05%
Next 4720 therms per therm	681,375	$0.15686	$106,880	$0.17419	$118,689	$11,808	11.05%
Over 5,000 therms per therm	458,315	$0.05028	$23,044	$0.05584	$25,592	$2,548	11.06%
Economic Development Discount			($6,097)		($6,097)	$0	0.00%
Energy Revenue	1,315,652		$170,413		$189,916	$19,503	11.44%
Adjustment Factor	1.00000		1.00000		same		
Total Billed Energy Revenue	1,315,652		$170,413		$189,916	$19,503	11.44%
Total Delivery Revenue			$181,114		$202,995	$21,881	12.08%
SBC		$0	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$602	$0.00046	$602	$0	0.00%
Subtotal before GRT			$181,716		$203,597	$21,881	12.04%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
TOTAL REVENUE			$181,716		$203,597	$21,881	12.04%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ANALYSIS OF PRESENT AND PROPOSED RATES
Based on Twelve Months Ended March 31, 2010
PSC NO. 219- SC 12-Distributed Generation Service - Less than 250,000 Therms
RATE DESIGN

		Current Rates		Proposed Rates			Percent
	Bills/therms	Rate	Revenue	Rate	Revenue	Increase	Increase
Bills	12	$100.00000	$1,200	$147.65	$1,772	$572	47.65%
Adjustment Factor		-	1.00000				
Bills Adjusted	12	$100.00000	$1,200	$ 147.65	$1,772	$572	47.65%
0 - 3 therms	25						
Over 3 Therms per Therm(April - October)	147,307	$0.04149	$6,112	$0.04755	$7,004	$893	14.61%
Over 3 Therms per Therm (November - March)	105,220	$0.05256	$5,530	$0.06024	$6,338	$808	14.61%
Energy Revenue	252,552		$11,642		$13,343	$1,701	14.61%
Adjustment Factor	1.00000		1.00000		1.00000		
Total Billed Energy Revenue	252,552		$11,642		$13,343	$1,701	14.61%
Total Delivery Revenue			$12,842		$15,115	$2,273	17.70%
MCG Revenue w/o GRT			$193,076		$193,076	$0	0.00%
Merchant Function Charge		$0.02222	$5,612	$0.02086	$5,268	($343)	-6.12%
SBC		$0.00000	$0	$0.00000	$0	$0	0.00%
Misc Rev (R&D)		$0.00046	$115	$0.00046	$115	$0	0.00%
Subtotal			$211,645		$213,574	$1,929	0.91%
Delivery GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Commodity GRT		0.0000%	$0	0.0000%	$0	$0	0.00%
Muni GRT		0.5783%	$1,224	0.5783%	$1,235	$11	0.91%
TOTAL REVENUE			$212,869		$214,809	$1,940	0.91%

Settlement 02/13/2009
Statement Type: MFC
Statement No. 1

PSC No. 219 Gas
Company: Niagara Mohawk Power Corporation d/b/a National Grid
Initial Effective Date: 5/20/2009

Merchant Function Charge
with Updated Gas Costs - 12/28/2008
Effective with Usage on or after the effective date of this statement and thereafter until changed

		SC1	SC2	SC2	SC12	SC13
					Distributed Generatio	Distributed Generation
		Residential	:esidential & Commercial	Industrial	Non-Residential	Residential
		$ Per Therm	$ Per Therm	$ Per Therm	$ Per Therm	$ Per Therm
	Monthly Gas Supply Charge Forecast for Rate Year TME Mar	$ 0.8426	$ 0.8420	$ 0.8030	$ 0.7645	$ 0.8066
	Uncollectible Factor	2.30%	0.30%	0.30%	0.30%	0.30%
	1 Uncollectible Charge (Monthly Gas Supply Charge * Uncollec	$ 0.01938	$ 0.00253	$ 0.00241	$ 0.00229	$ 0.00242
	2 Gas Supply Procurement	$ 0.00196	$ 0.00196	$ 0.00196	$ 0.00196	$ 0.00196
	3 Records and Collection Charge	$ 0.00419	$ 0.00419	$ 0.00419	$ 0.00419	$ 0.00419
	4 Gas Storage Inventory Carrying Charge	$ 0.01241	$ 0.01241	$ 0.01241	$ 0.01241	$ 0.01241
Sum 1-4	Total Merchant Function Charge	$ 0.03794	$ 0.02109	$ 0.02097	$ 0.02086	$ 0.02098

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

ALLOCATION OF PROPOSED GAS REVENUE REQUIREMENT

Twelve Months Ended March 31, 2010

Rate Design results reflecting
Mains classified 35%
Customer/65% Demand
Throughput Forecast per Settlement

RATE YEAR 1

1	2	3	4	5	6	7	8	9	10	11	12	13			14	15	16	17	18
Service Class	Total Revenue	GRT	Commodity Revenue	Delivery Revenue Yr 1 (2)-(3)-(4)	Mis Rev - Not MFC	Misc Rev - MFC	Customer Margin (5)-(6)	Deficiency / Surplus	Realigned Rate Yr 1 Customer Margin	Percent	Cust Chg Increase to 4 & 6	Allocated Rate Increase w/o GRT	LOW INCOME PROGRAM Recovery	LOW INCOME PROGRAM Credits	Total Allocated Increase	Deficiency / Surplus	Adjusted Allocated rate Increase	Rate Design Increase before GRT	Difference Between Actual and Target
SC1 & SC1 MB	$553,769,012	$6,651,501	$356,980,625	$190,136,886	$242,932	$9,413,427	$189,893,954	($8,944,386)	$198,838,341	76.52%		$29,457,706	4,144,674	(4,500,000)	$29,102,379	$0	$29,102,379	$29,103,483	$1,104
SC2 & SC2 MB	$151,919,749	$761,369	$100,148,449	$51,009,931	($122,351)	$2,644,802	$51,132,282	$10,378,549	$40,753,733	15.68%		$6,037,626	348,072	-	$6,385,698	$0	$6,385,698	$6,383,657	($2,040)
SC3	$3,821,481	$21,962	$3,283,556	$515,963	$96,009	$0	$419,954	$242,200	$177,754	0.07%		$26,334	257	-	$26,591	$0	$26,591	$25,660	($931)
SC4	$7,199,162	$41,372	$6,554,653	$603,137	$0	$0	$603,137	$0	$603,137	0.00%	$14,314	$0	16	-	$14,330	$0	$14,330	$14,314	($16)
SC5	$4,086,518	$0	$0	$4,086,518	($16,732)	$0	$4,103,250	($326,729)	$4,429,979	1.70%		$656,297	1,236	-	$657,533	$0	$657,533	$689,462	$31,928
SC6	$4,764,820	$0	$0	$4,764,820	$0	$0	$4,764,820	$0	$4,764,820	0.00%	$63,659	$0	179	-	$63,838	$0	$63,838	$63,659	($179)
SC7	$6,921,425	$0	$0	$6,921,425	$12,672	$0	$6,908,753	$0	$6,908,753	2.66%		$1,023,525	5,132	-	$1,028,657	$0	$1,028,657	$1,035,893	$7,236
SC8	$26,669,698	$0	$19,490,095	$7,179,603	$20,042	$0	$7,159,561	($1,301,717)	$8,461,279	3.26%		$1,253,530	420	-	$1,253,950	$0	$1,253,950	$1,203,503	($50,447)
NYSEG	$231,608	$0	$0	$231,608	$0	$0	$231,608	($47,916)	$279,525	0.11%		$41,411	8	-	$41,419	$0	$41,419	$40,785	($634)
SC12 DG < 250K	$212,869	$1,224	$193,076	$18,569	$115	$5,612	$18,454	$0	$18,454	0.01%		$2,734	8	-	$2,742	$0	$2,742	$1,929	($813)
Subtotal	$759,596,342	$7,477,428	$486,650,454	$265,468,460	$232,687	$12,063,841	$265,235,773	$0	$265,235,773	100.00%	$77,974	$38,499,163	4,500,000	(4,500,000)	$38,577,137	$0	$38,577,137	$38,562,346	($14,791)
Late Payment Revenue	$3,279,228	$46,575	$0	$3,232,653	$0	$0	$3,232,653	$0	$3,232,653	n/a	$332	$164,654			$164,985	$0	$164,985	$164,985	$0
SC12 DG > 250K < 1 Million	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%		$0			$0	$0	$0	$0	$0
SC12 DG > 1 Million < 2.5 Million	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%		$0			$0	$0	$0	$0	$0
SC12 DG > 2.5 Million	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%		$0			$0	$0	$0	$0	$0
SC13 DG	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%		$0			$0	$0	$0	$0	$0
SC10	$3,409	$23	$2,114	$1,272	$0	$0	$1,272	$0	$1,272	0.00%		$0			$0	$0	$0	$0	$0
SC9	$11,506,867	$126,573	$0	$11,380,294	$0	$0	$11,380,294	$0	$11,380,294	0.00%		$0			$0	$0	$0	$0	$0
SC14	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%		$0			$0	$0	$0	$0	$0
							$0								$0				
Misc	$899,124	$0	$0	$899,124	$0	$0	$899,124	$0	$899,124	0.00%		$54,000			$54,000	$0	$54,000	$54,000	$0
Total Company	$775,284,970	$7,650,599	$486,652,568	$280,981,803	$232,687	$12,063,841	$280,749,116	$0	$280,749,116	100.00%	$78,305	$38,717,817	4,500,000	(4,500,000)	$38,796,122	$0	$38,796,122	$38,781,331	($14,791)

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC1 Non Heat

Case 08-G-0609
Section 2.2.2
Sheet 1 of 12

Use	Present Bill	Proposed Bill	Increase	Percent
0	$15.01	$17.81	$2.80	18.63%
3	$17.90	$20.72	$2.82	15.77%
10	$27.14	$30.30	$3.16	11.64%
15	$33.74	$37.13	$3.40	10.07%
20	$40.33	$43.97	$3.64	9.02%
25	$46.93	$50.81	$3.88	8.26%
30	$53.53	$57.65	$4.12	7.69%
40	$66.73	$71.32	$4.59	6.89%
50	$79.92	$85.00	$5.07	6.35%
60	$90.10	$95.32	$5.22	5.80%
70	$100.28	$105.65	$5.37	5.36%
80	$110.45	$115.97	$5.52	5.00%
100	$130.80	$136.62	$5.82	4.45%
120	$151.16	$157.28	$6.12	4.05%
140	$171.51	$177.93	$6.42	3.74%
160	$191.86	$198.58	$6.72	3.50%
180	$212.21	$219.23	$7.02	3.31%
200	$232.56	$239.88	$7.31	3.15%
220	$252.92	$260.53	$7.61	3.01%
250	$283.45	$291.51	$8.06	2.84%
300	$334.33	$343.14	$8.81	2.63%
400	$436.09	$446.39	$10.30	2.36%

First 3 or Less	$14.71	$17.45	$2.74	18.63%
Next 47 Therms per therm	$0.349210	$0.387280	$0.03807	10.90%
Over 50 Therms per Therm	$0.053220	$0.059020	$0.00580	10.90%
Delivery Service Adjustment	$0.006914	$0.000354	($0.00656)	-94.88%
SBC	$0.006700	$0.006700	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.037940	$0.01572	70.75%
GRT on Delivery	2.040820%	2.040820%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.927330	$0.927330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC1 Heat

Case 08-G-0609
Appendix E
Sheet 2 of 12

	Use	Present Bill	Proposed Bill	Increase	Percent
	25	$46.93	$50.81	$3.88	8.26%
	30	$53.53	$57.65	$4.12	7.69%
	40	$66.73	$71.32	$4.59	6.89%
	50	$79.92	$85.00	$5.07	6.35%
	60	$90.10	$95.32	$5.22	5.80%
	70	$100.28	$105.65	$5.37	5.36%
	80	$110.45	$115.97	$5.52	5.00%
	100	$130.80	$136.62	$5.82	4.45%
	120	$151.16	$157.28	$6.12	4.05%
	140	$171.51	$177.93	$6.42	3.74%
	160	$191.86	$198.58	$6.72	3.50%
	180	$212.21	$219.23	$7.02	3.31%
	200	$232.56	$239.88	$7.31	3.15%
	220	$252.92	$260.53	$7.61	3.01%
	250	$283.45	$291.51	$8.06	2.84%
	300	$334.33	$343.14	$8.81	2.63%
	400	$436.09	$446.39	$10.30	2.36%
	500	$537.85	$549.65	$11.80	2.19%
	600	$639.61	$652.90	$13.29	2.08%
	800	$843.13	$859.41	$16.28	1.93%
	1000	$1,046.65	$1,065.92	$19.27	1.84%
	2000	$2,064.27	$2,098.48	$34.21	1.66%
First 3 or Less		$14.71	$17.45	$2.74	18.63%
Next 47 Therms per Therm		$0.349210	$0.387280	$0.03807	10.90%
Over 50 Therms per Therm		$0.053220	$0.059020	$0.00580	10.90%
Delivery Service Adjustment		$0.006914	$0.000354	($0.00656)	-94.88%
SBC		$0.006700	$0.006700	$0.00000	0.00%
Merchant Function Charge		$0.022220	$0.037940	$0.01572	70.75%
GRT on Delivery		2.040820%	2.040820%	$0.00000	0.00%
GRT on Supply		0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate		$0.927330	$0.927330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC1 Heat Low Income

Case 08-G-0609
Section 2.2.2
Sheet 3 of 12

Use	Present Bill	Proposed Bill	Increase	Percent
25	$46.93	$43.16	($3.78)	-8.05%
30	$53.53	$49.99	($3.54)	-6.61%
40	$66.73	$63.67	($3.06)	-4.58%
50	$79.92	$77.34	($2.58)	-3.23%
60	$90.10	$87.67	($2.43)	-2.70%
70	$100.28	$97.99	($2.28)	-2.27%
80	$110.45	$108.32	($2.13)	-1.93%
100	$130.80	$128.97	($1.83)	-1.40%
120	$151.16	$149.62	($1.53)	-1.01%
140	$171.51	$170.27	($1.24)	-0.72%
160	$191.86	$190.92	($0.94)	-0.49%
180	$212.21	$211.58	($0.64)	-0.30%
200	$232.56	$232.23	($0.34)	-0.15%
220	$252.92	$252.88	($0.04)	-0.02%
250	$283.45	$283.85	$0.41	0.14%
300	$334.33	$335.48	$1.16	0.35%
400	$436.09	$438.74	$2.65	0.61%
500	$537.85	$541.99	$4.14	0.77%
600	$639.61	$645.25	$5.64	0.88%
800	$843.13	$851.76	$8.63	1.02%
1000	$1,046.65	$1,058.27	$11.62	1.11%
2000	$2,064.27	$2,090.83	$26.56	1.29%

First 3 or Less	$14.71	$9.95	($4.76)	-32.36%
Next 47 Therms per Therm	$0.349210	$0.387280	$0.03807	10.90%
Over 50 Therms per Therm	$0.053220	$0.059020	$0.00580	10.90%
Delivery Service Adjustment	$0.006914	$0.000354	($0.00656)	-94.88%
SBC	$0.006700	$0.006700	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.037940	$0.01572	70.75%
GRT on Delivery	2.040820%	2.040820%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.927330	$0.927330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC2 Customers

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	Use	Present Bill	Proposed Bill	Increase	Percent
	0	$19.35	$23.65	$4.30	22.22%
	3	$22.24	$26.52	$4.28	19.23%
	10	$30.87	$35.30	$4.43	14.36%
	15	$37.03	$41.58	$4.54	12.26%
	20	$43.20	$47.85	$4.65	10.77%
	25	$49.36	$54.12	$4.76	9.65%
	30	$55.53	$60.40	$4.87	8.78%
	40	$67.85	$72.95	$5.09	7.51%
	50	$80.18	$85.50	$5.32	6.63%
	60	$92.51	$98.05	$5.54	5.98%
	70	$104.84	$110.60	$5.76	5.49%
	80	$117.17	$123.15	$5.98	5.10%
	100	$141.82	$148.24	$6.42	4.53%
	120	$166.48	$173.34	$6.86	4.12%
	140	$191.14	$198.44	$7.30	3.82%
	160	$215.79	$223.54	$7.75	3.59%
	180	$240.45	$248.64	$8.19	3.41%
	200	$265.11	$273.74	$8.63	3.26%
	250	$326.75	$336.48	$9.74	2.98%
	280	$363.73	$374.13	$10.40	2.86%
	300	$386.13	$396.72	$10.59	2.74%
	400	$498.13	$509.69	$11.56	2.32%
	500	$610.14	$622.66	$12.52	2.05%
	600	$722.14	$735.62	$13.48	1.87%
	1000	$1,170.15	$1,187.49	$17.34	1.48%
	1500	$1,730.16	$1,752.32	$22.16	1.28%
	2000	$2,290.17	$2,317.15	$26.98	1.18%
	2570	$2,928.59	$2,961.06	$32.47	1.11%
	3000	$3,410.20	$3,446.82	$36.62	1.07%
	5000	$5,650.25	$5,706.14	$55.90	0.99%
	9000	$9,704.02	$9,751.40	$47.38	0.49%
	10000	$10,717.47	$10,762.71	$45.25	0.42%
First 3 or Less		$19.35	$23.65	$4.30	22.22%
Next 277 Therms per therm		$0.269660	$0.299450	$0.02979	11.05%
Next 4720 Therms per therm		$0.156860	$0.174190	$0.01733	11.05%
Over 5000 Therms per Therm		$0.050280	$0.055840	$0.00556	11.06%
Delivery Service Adjustment		$0.006914	$0.000354	($0.00656)	-94.88%
SBC		$0.006700	$0.006700	$0.00000	0.00%
Merchant Function Charge		$0.022220	$0.021090	($0.00113)	-5.09%
GRT on Delivery		0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply		0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate		$0.927330	$0.927330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC3 Customers

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Use	Present Bill	Proposed Bill	Increase	Percent
5000	$5,357.08	$5,324.93	($32.15)	-0.60%
6000	$6,318.34	$6,335.08	$16.74	0.26%
7000	$7,279.61	$7,345.24	$65.63	0.90%
8000	$8,240.87	$8,355.39	$114.52	1.39%
9000	$9,202.14	$9,365.55	$163.41	1.78%
10000	$10,163.40	$10,375.70	$212.30	2.09%
11000	$11,124.66	$11,385.85	$261.19	2.35%
12000	$12,085.93	$12,396.01	$310.08	2.57%
13000	$13,047.19	$13,406.16	$358.97	2.75%
14000	$14,008.46	$14,416.32	$407.86	2.91%
15000	$14,969.72	$15,426.47	$456.75	3.05%
18000	$17,853.51	$18,456.93	$603.42	3.38%
21000	$20,737.30	$21,487.39	$750.09	3.62%
24000	$23,621.10	$24,517.86	$896.76	3.80%
27000	$26,504.89	$27,548.32	$1,043.43	3.94%
30000	$29,388.68	$30,578.78	$1,190.10	4.05%
35000	$34,195.00	$35,629.55	$1,434.55	4.20%
40000	$39,001.32	$40,680.32	$1,679.00	4.30%
45000	$43,807.64	$45,731.09	$1,923.45	4.39%
50000	$48,613.96	$50,781.86	$2,167.90	4.46%
60000	$58,226.60	$60,883.40	$2,656.80	4.56%
70000	$67,839.24	$70,984.94	$3,145.70	4.64%

First 5,000 or Less	$782.11	$782.76	$0.65	0.08%
Over 5,000 Thms per Thm	$0.046270	$0.101720	$0.05545	119.84%
	$0.000000	$0.000000	$0.00000	0.00%
Delivery Service Adjustment	$0.006914	$0.000354	($0.00656)	-94.88%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.000000	$0.000000	$0.00000	0.00%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.908080	$0.908080	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC5 Customers

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	Use	Present Bill	Proposed Bill	Increase	Percent
	20000	$1,397.92	$1,653.87	$255.95	18.31%
	23000	$1,555.31	$1,832.95	$277.64	17.85%
	26000	$1,712.70	$2,012.03	$299.33	17.48%
	29000	$1,870.10	$2,191.11	$321.02	17.17%
	32000	$2,027.49	$2,370.19	$342.71	16.90%
	35000	$2,184.88	$2,549.28	$364.40	16.68%
	38000	$2,342.27	$2,728.36	$386.09	16.48%
	41000	$2,499.66	$2,907.44	$407.78	16.31%
	44000	$2,657.06	$3,086.52	$429.47	16.16%
	47000	$2,814.45	$3,265.60	$451.16	16.03%
	50000	$2,971.84	$3,444.69	$472.85	15.91%
	53000	$3,129.23	$3,623.77	$494.54	15.80%
	56000	$3,286.62	$3,802.85	$516.23	15.71%
	59000	$3,444.02	$3,981.93	$537.92	15.62%
	62000	$3,601.41	$4,161.01	$559.61	15.54%
	65000	$3,758.80	$4,340.10	$581.30	15.46%
	68000	$3,916.19	$4,519.18	$602.99	15.40%
	71000	$4,073.58	$4,698.26	$624.68	15.33%
	74000	$4,230.98	$4,877.34	$646.37	15.28%
	77000	$4,388.37	$5,056.42	$668.06	15.22%
	80000	$4,545.76	$5,235.51	$689.75	15.17%
	83000	$4,703.15	$5,414.59	$711.44	15.13%
First 100 or Less		$353.85	$465.92	$112.07	31.67%
Over 100 Therms per therm		$0.052110	$0.059340	$0.00723	13.87%
Delivery Service Adjustment		$0.000354	$0.000354	$0.00000	0.00%
SBC		$0.000000	$0.000000	$0.00000	0.00%
GRT on Delivery		0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply		0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate		$0.000000	$0.000000	$0.00000	0.00%
		$0.000000	$0.000000	$0.00000	0.00%

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Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC7 Customers

Use	Present Bill	Proposed Bill	Increase	Percent
1000	$303.65	$358.00	$54.35	17.90%
3000	$397.37	$478.71	$81.34	20.47%
7000	$812.14	$980.68	$168.54	20.75%
9000	$1,019.53	$1,231.67	$212.14	20.81%
11000	$1,226.92	$1,482.66	$255.74	20.84%
13000	$1,434.31	$1,733.65	$299.34	20.87%
15000	$1,641.70	$1,984.64	$342.94	20.89%
17000	$1,849.08	$2,235.62	$386.54	20.90%
20000	$2,160.17	$2,612.11	$451.94	20.92%
25000	$2,678.64	$3,239.58	$560.94	20.94%
30000	$3,197.11	$3,867.05	$669.94	20.95%
35000	$3,715.58	$4,494.52	$778.94	20.96%
40000	$4,234.05	$5,121.99	$887.94	20.97%
45000	$4,752.52	$5,749.46	$996.94	20.98%
50000	$5,270.99	$6,376.93	$1,105.94	20.98%
55000	$5,789.46	$7,004.40	$1,214.94	20.99%
60000	$6,307.93	$7,631.87	$1,323.94	20.99%
65000	$6,826.40	$8,259.34	$1,432.94	20.99%
70000	$7,344.87	$8,886.81	$1,541.94	20.99%
75000	$7,863.34	$9,514.28	$1,650.94	21.00%
80000	$8,381.81	$10,141.75	$1,759.94	21.00%
85000	$8,900.28	$10,769.22	$1,868.94	21.00%

First 2100 or Less	$303.30	$350.95	$47.65	15.71%
Over 2100 Therms per therm	$0.103340	$0.118440	$0.01510	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.006700	$0.00670	N/A
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.000000	$0.000000	$0.00000	0.00%
	$0.000000	$0.000000	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates -SC8 Customers

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Use	Present Bill	Proposed Bill	Increase	Percent
20000	$1,751.77	$2,013.60	$261.83	14.95%
23000	$1,909.16	$2,192.68	$283.52	14.85%
26000	$2,066.55	$2,371.76	$305.21	14.77%
29000	$2,223.95	$2,550.84	$326.90	14.70%
32000	$2,381.34	$2,729.92	$348.59	14.64%
35000	$2,538.73	$2,909.01	$370.28	14.59%
38000	$2,696.12	$3,088.09	$391.97	14.54%
41000	$2,853.51	$3,267.17	$413.66	14.50%
44000	$3,010.91	$3,446.25	$435.35	14.46%
47000	$3,168.30	$3,625.33	$457.04	14.43%
50000	$3,325.69	$3,804.42	$478.73	14.39%
60000	$3,850.33	$4,401.36	$551.03	14.31%
70000	$4,374.97	$4,998.30	$623.33	14.25%
80000	$4,899.61	$5,595.24	$695.63	14.20%
100000	$5,948.89	$6,789.12	$840.23	14.12%
150000	$8,325.09	$9,613.32	$1,288.23	15.47%
200000	$10,701.29	$12,437.52	$1,736.23	16.22%
250000	$13,077.49	$15,261.72	$2,184.23	16.70%
300000	$15,453.69	$18,085.92	$2,632.23	17.03%
400000	$20,206.09	$23,734.32	$3,528.23	17.46%
500000	$24,958.49	$29,382.72	$4,424.23	17.73%
600000	$29,037.89	$34,260.12	$5,222.23	17.98%

First 100 or Less	$707.70	$825.65	$117.95	16.67%
Next 99900 Therms per therm	$0.052110	$0.059340	$0.00723	13.87%
Next 400000 Therms per therm	$0.047170	$0.056130	$0.00896	19.00%
Over 500000 Therms per Therm	$0.040440	$0.048420	$0.00798	19.73%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.000000	$0.000000	$0.00000	0.00%
	$0.000000	$0.000000	$0.00000	0.00%

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Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Summer (April - October)
Less Than 250,000 Therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
0	$100.00	$147.65	$47.65	47.65%
3	$102.72	$150.36	$47.65	46.39%
100	$194.61	$242.72	$48.10	24.72%
200	$289.35	$337.93	$48.57	16.79%
400	$478.83	$528.34	$49.51	10.34%
600	$668.31	$718.76	$50.45	7.55%
800	$857.79	$909.18	$51.39	5.99%
900	$952.53	$1,004.39	$51.86	5.44%
1000	$1,047.27	$1,099.60	$52.33	5.00%
2000	$1,994.66	$2,051.70	$57.03	2.86%
3000	$2,942.06	$3,003.79	$61.73	2.10%
4000	$3,889.45	$3,955.88	$66.43	1.71%
5000	$4,836.85	$4,907.98	$71.13	1.47%
6000	$5,784.24	$5,860.07	$75.83	1.31%
8000	$7,679.03	$7,764.26	$85.23	1.11%
10000	$9,573.82	$9,668.45	$94.63	0.99%
12000	$11,468.60	$11,572.64	$104.03	0.91%
14000	$13,363.39	$13,476.82	$113.43	0.85%
16000	$15,258.18	$15,381.01	$122.83	0.81%
18000	$17,152.97	$17,285.20	$132.23	0.77%
20000	$19,047.76	$19,189.39	$141.63	0.74%
21000	$19,995.15	$20,141.48	$146.33	0.73%

	Present	Proposed	Increase	Percent
First 3 or Less	$100.00	$147.65	$47.65	47.65%
Over 3 Therms (Apr-Oct)	$0.04149	$0.04755	$0.00606	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.00000	$0.00000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Winter (November - March)
Less Than 250,000 Therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
0	$100.00	$147.65	$47.65	47.65%
3	$102.72	$150.36	$47.65	46.39%
100	$195.69	$243.95	$48.26	24.66%
200	$291.54	$340.43	$48.89	16.77%
400	$483.23	$533.38	$50.15	10.38%
600	$674.92	$726.34	$51.42	7.62%
800	$866.61	$919.30	$52.68	6.08%
900	$962.46	$1,015.77	$53.31	5.54%
1000	$1,058.31	$1,112.25	$53.95	5.10%
2000	$2,016.77	$2,077.04	$60.27	2.99%
3000	$2,975.23	$3,041.82	$66.59	2.24%
4000	$3,933.70	$4,006.61	$72.91	1.85%
5000	$4,892.16	$4,971.39	$79.23	1.62%
6000	$5,850.63	$5,936.17	$85.55	1.46%
8000	$7,767.55	$7,865.74	$98.19	1.26%
10000	$9,684.48	$9,795.31	$110.83	1.14%
12000	$11,601.41	$11,724.88	$123.47	1.06%
14000	$13,518.34	$13,654.45	$136.11	1.01%
16000	$15,435.27	$15,584.01	$148.75	0.96%
18000	$17,352.19	$17,513.58	$161.39	0.93%
20000	$19,269.12	$19,443.15	$174.03	0.90%
21000	$20,227.59	$20,407.93	$180.35	0.89%

	Present	Proposed	Increase	Percent
First 3 or Less	$100.00	$147.65	$47.65	47.65%
Over 3 Therms (Nov-Mar)	$0.05256	$0.06024	$0.00768	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.00000	$0.00000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

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Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Summer (April - October)
250,000 Therms to 1,000,000 therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
20000	$19,211.22	$19,404.07	$192.85	1.00%
21000	$20,154.09	$20,350.99	$196.89	0.98%
22000	$21,096.97	$21,297.90	$200.93	0.95%
24000	$22,982.72	$23,191.73	$209.01	0.91%
25000	$23,925.59	$24,138.64	$213.05	0.89%
26000	$24,868.46	$25,085.56	$217.09	0.87%
27000	$25,811.34	$26,032.47	$221.13	0.86%
28000	$26,754.21	$26,979.38	$225.17	0.84%
29000	$27,697.09	$27,926.30	$229.21	0.83%
30000	$28,639.96	$28,873.21	$233.25	0.81%
32000	$30,525.71	$30,767.04	$241.33	0.79%
34000	$32,411.46	$32,660.87	$249.41	0.77%
36000	$34,297.20	$34,554.70	$257.49	0.75%
38000	$36,182.95	$36,448.52	$265.57	0.73%
40000	$38,068.70	$38,342.35	$273.65	0.72%
42000	$39,954.45	$40,236.18	$281.73	0.71%
44000	$41,840.20	$42,130.01	$289.81	0.69%
46000	$43,725.94	$44,023.84	$297.89	0.68%
48000	$45,611.69	$45,917.66	$305.97	0.67%
50000	$47,497.44	$47,811.49	$314.05	0.66%
52000	$49,383.19	$49,705.32	$322.13	0.65%
54000	$51,268.94	$51,599.15	$330.21	0.64%
56000	$53,154.68	$53,492.98	$338.29	0.64%
58000	$55,040.43	$55,386.80	$346.37	0.63%
60000	$56,926.18	$57,280.63	$354.45	0.62%
62000	$58,811.93	$59,174.46	$362.53	0.62%
64000	$60,697.68	$61,068.29	$370.61	0.61%
66000	$62,583.42	$62,962.12	$378.69	0.61%
68000	$64,469.17	$64,855.94	$386.77	0.60%
70000	$66,354.92	$66,749.77	$394.85	0.60%
75000	$71,069.29	$71,484.34	$415.05	0.58%
80000	$75,783.66	$76,218.91	$435.25	0.57%

First 3 or Less	$353.85	$465.92	$112.07	31.67%
Over 3 Therms (Apr - Oct)	$0.036970	$0.042370	$0.00540	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Winter (November - March)
250,000 Therms to 1,000,000 therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
20000	$19,408.39	$19,630.04	$221.65	1.14%
21000	$20,361.12	$20,588.25	$227.13	1.12%
22000	$21,313.86	$21,546.47	$232.61	1.09%
24000	$23,219.33	$23,462.89	$243.57	1.05%
25000	$24,172.06	$24,421.11	$249.05	1.03%
26000	$25,124.79	$25,379.32	$254.53	1.01%
27000	$26,077.53	$26,337.54	$260.01	1.00%
28000	$27,030.26	$27,295.75	$265.49	0.98%
29000	$27,983.00	$28,253.96	$270.97	0.97%
30000	$28,935.73	$29,212.18	$276.45	0.96%
32000	$30,841.20	$31,128.61	$287.41	0.93%
34000	$32,746.67	$33,045.03	$298.37	0.91%
36000	$34,652.13	$34,961.46	$309.33	0.89%
38000	$36,557.60	$36,877.89	$320.29	0.88%
40000	$38,463.07	$38,794.32	$331.25	0.86%
42000	$40,368.54	$40,710.75	$342.21	0.85%
44000	$42,274.01	$42,627.17	$353.17	0.84%
46000	$44,179.47	$44,543.60	$364.13	0.82%
48000	$46,084.94	$46,460.03	$375.09	0.81%
50000	$47,990.41	$48,376.46	$386.05	0.80%
52000	$49,895.88	$50,292.89	$397.01	0.80%
54000	$51,801.35	$52,209.31	$407.97	0.79%
56000	$53,706.81	$54,125.74	$418.93	0.78%
58000	$55,612.28	$56,042.17	$429.89	0.77%
60000	$57,517.75	$57,958.60	$440.85	0.77%
62000	$59,423.22	$59,875.03	$451.81	0.76%
64000	$61,328.69	$61,791.45	$462.77	0.75%
66000	$63,234.15	$63,707.88	$473.73	0.75%
68000	$65,139.62	$65,624.31	$484.69	0.74%
70000	$67,045.09	$67,540.74	$495.65	0.74%
75000	$71,808.76	$72,331.81	$523.05	0.73%
80000	$76,572.43	$77,122.88	$550.45	0.72%

First 3 or Less	$353.85	$465.92	$112.07	31.67%
Over 3 Therms (Nov - Mar)	$0.046830	$0.053670	$0.00684	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Summer (April - October)
1,000,000 Therms to 2,500,000 therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
80000	$76,626.47	$76,921.02	$294.55	0.38%
82000	$78,507.22	$78,809.13	$301.91	0.38%
84000	$80,387.97	$80,697.24	$309.27	0.38%
86000	$82,268.72	$82,585.34	$316.63	0.38%
88000	$84,149.47	$84,473.45	$323.99	0.39%
90000	$86,030.21	$86,361.56	$331.35	0.39%
92000	$87,910.96	$88,249.67	$338.71	0.39%
94000	$89,791.71	$90,137.78	$346.07	0.39%
96000	$91,672.46	$92,025.88	$353.43	0.39%
98000	$93,553.21	$93,913.99	$360.79	0.39%
100000	$95,433.95	$95,802.10	$368.15	0.39%
105000	$100,135.82	$100,522.37	$386.55	0.39%
110000	$104,837.69	$105,242.64	$404.95	0.39%
115000	$109,539.56	$109,962.91	$423.35	0.39%
120000	$114,241.43	$114,683.18	$441.75	0.39%
125000	$118,943.30	$119,403.45	$460.15	0.39%
130000	$123,645.17	$124,123.72	$478.55	0.39%
135000	$128,347.04	$128,843.99	$496.95	0.39%
140000	$133,048.91	$133,564.26	$515.35	0.39%
145000	$137,750.78	$138,284.53	$533.75	0.39%
150000	$142,452.65	$143,004.80	$552.15	0.39%
155000	$147,154.52	$147,725.07	$570.55	0.39%
160000	$151,856.39	$152,445.34	$588.95	0.39%
165000	$156,558.26	$157,165.61	$607.35	0.39%
170000	$161,260.13	$161,885.88	$625.75	0.39%
175000	$165,962.00	$166,606.15	$644.15	0.39%
180000	$170,663.87	$171,326.42	$662.55	0.39%
185000	$175,365.74	$176,046.69	$680.95	0.39%
190000	$180,067.61	$180,766.96	$699.35	0.39%
195000	$184,769.48	$185,487.23	$717.75	0.39%
200000	$189,471.35	$190,207.50	$736.15	0.39%
205000	$194,173.22	$194,927.77	$754.55	0.39%

	Present	Proposed	Increase	Percent
First 100 or Less	$1,400.00	$1,400.65	$0.65	0.05%
Next 499,900 Therms (Apr - Oct)	$0.034470	$0.039510	$0.00504	14.62%
Over 500,000 Therms (Apr - Oct)	$0.029550	$0.033870	$0.00432	14.62%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Winter (November - March)
1,000,000 Therms to 2,500,000 therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
80000	$77,360.75	$77,762.37	$401.61	0.52%
82000	$79,259.88	$79,671.53	$411.65	0.52%
84000	$81,159.01	$81,580.70	$421.69	0.52%
86000	$83,058.14	$83,489.87	$431.73	0.52%
88000	$84,957.27	$85,399.04	$441.77	0.52%
90000	$86,856.39	$87,308.21	$451.81	0.52%
92000	$88,755.52	$89,217.37	$461.85	0.52%
94000	$90,654.65	$91,126.54	$471.89	0.52%
96000	$92,553.78	$93,035.71	$481.93	0.52%
98000	$94,452.91	$94,944.88	$491.97	0.52%
100000	$96,352.03	$96,854.05	$502.01	0.52%
105000	$101,099.85	$101,626.97	$527.11	0.52%
110000	$105,847.67	$106,399.89	$552.21	0.52%
115000	$110,595.49	$111,172.81	$577.31	0.52%
120000	$115,343.31	$115,945.73	$602.41	0.52%
125000	$120,091.13	$120,718.65	$627.51	0.52%
130000	$124,838.95	$125,491.57	$652.61	0.52%
135000	$129,586.77	$130,264.49	$677.71	0.52%
140000	$134,334.59	$135,037.41	$702.81	0.52%
145000	$139,082.41	$139,810.33	$727.91	0.52%
150000	$143,830.23	$144,583.25	$753.01	0.52%
155000	$148,578.05	$149,356.17	$778.11	0.52%
160000	$153,325.87	$154,129.09	$803.21	0.52%
165000	$158,073.69	$158,902.01	$828.31	0.52%
170000	$162,821.51	$163,674.93	$853.41	0.52%
175000	$167,569.33	$168,447.85	$878.51	0.52%
180000	$172,317.15	$173,220.77	$903.61	0.52%
185000	$177,064.97	$177,993.69	$928.71	0.52%
190000	$181,812.79	$182,766.61	$953.81	0.52%
195000	$186,560.61	$187,539.53	$978.91	0.52%
200000	$191,308.43	$192,312.45	$1,004.01	0.52%
205000	$196,056.25	$197,085.37	$1,029.11	0.52%

	Present	Proposed	Increase	Percent
First 100 or Less	$1,400.00	$1,400.65	$0.65	0.05%
Next 499,900 Therms (Nov - Mar)	$0.043660	$0.050040	$0.00638	14.61%
Over 500,000 Therms (Nov - Mar)	$0.037430	$0.042900	$0.00547	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Summer (April - October)
Greater Than 2,500,000 Therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
200000	$188,929.88	$189,586.45	$656.57	0.35%
210000	$198,306.38	$198,995.74	$689.36	0.35%
220000	$207,682.88	$208,405.04	$722.16	0.35%
230000	$217,059.37	$217,814.33	$754.96	0.35%
240000	$226,435.87	$227,223.62	$787.75	0.35%
250000	$235,812.36	$236,632.91	$820.55	0.35%
260000	$245,188.86	$246,042.20	$853.34	0.35%
270000	$254,565.35	$255,451.49	$886.14	0.35%
280000	$263,941.85	$264,860.78	$918.94	0.35%
290000	$273,318.34	$274,270.07	$951.73	0.35%
300000	$282,694.84	$283,679.37	$984.53	0.35%
310000	$292,071.33	$293,088.66	$1,017.32	0.35%
320000	$301,447.83	$302,497.95	$1,050.12	0.35%
330000	$310,824.32	$311,907.24	$1,082.92	0.35%
340000	$320,200.82	$321,316.53	$1,115.71	0.35%
350000	$329,577.31	$330,725.82	$1,148.51	0.35%
360000	$338,953.81	$340,135.11	$1,181.30	0.35%
370000	$348,330.30	$349,544.40	$1,214.10	0.35%
380000	$357,706.80	$358,953.70	$1,246.90	0.35%
390000	$367,083.29	$368,362.99	$1,279.69	0.35%
400000	$376,459.79	$377,772.28	$1,312.49	0.35%
450000	$423,342.27	$424,818.74	$1,476.47	0.35%
500000	$470,224.74	$471,865.19	$1,640.45	0.35%
550000	$517,107.22	$518,911.65	$1,804.43	0.35%
600000	$563,989.70	$565,958.11	$1,968.41	0.35%
650000	$610,872.17	$613,004.56	$2,132.39	0.35%
700000	$657,754.65	$660,051.02	$2,296.37	0.35%
750000	$704,637.12	$707,097.47	$2,460.35	0.35%
800000	$751,519.60	$754,143.93	$2,624.33	0.35%
850000	$798,402.08	$801,190.39	$2,788.31	0.35%
900000	$845,284.55	$848,236.84	$2,952.29	0.35%
950000	$892,167.03	$895,283.30	$3,116.27	0.35%

First 3 or Less	$1,400.00	$1,400.65	$0.65	0.05%
Over 3 Therms (Apr - Oct)	$0.006910	$0.007920	$0.00101	14.62%
MPDQ Demand Charge	$0.755000	$0.865340	$0.11034	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Niagara Mohawk Power Corporation d/b/a National Grid
Comparison of Present & Proposed Rates
SC 12 Non Residential Distributed Generation Service - Winter (November - March)
1,000,000 Therms to 2,500,000 therms Annually

Use	Present Bill	Proposed Bill	Increase	Percent
200000	$189,299.88	$190,010.45	$710.57	0.38%
210000	$198,694.87	$199,440.94	$746.06	0.38%
220000	$208,089.87	$208,871.43	$781.56	0.38%
230000	$217,484.86	$218,301.92	$817.06	0.38%
240000	$226,879.86	$227,732.41	$852.55	0.38%
250000	$236,274.86	$237,162.90	$888.05	0.38%
260000	$245,669.85	$246,593.39	$923.54	0.38%
270000	$255,064.85	$256,023.89	$959.04	0.38%
280000	$264,459.84	$265,454.38	$994.54	0.38%
290000	$273,854.84	$274,884.87	$1,030.03	0.38%
300000	$283,249.83	$284,315.36	$1,065.53	0.38%
310000	$292,644.83	$293,745.85	$1,101.02	0.38%
320000	$302,039.82	$303,176.34	$1,136.52	0.38%
330000	$311,434.82	$312,606.83	$1,172.02	0.38%
340000	$320,829.81	$322,037.32	$1,207.51	0.38%
350000	$330,224.81	$331,467.82	$1,243.01	0.38%
360000	$339,619.80	$340,898.31	$1,278.50	0.38%
370000	$349,014.80	$350,328.80	$1,314.00	0.38%
380000	$358,409.79	$359,759.29	$1,349.50	0.38%
390000	$367,804.79	$369,189.78	$1,384.99	0.38%
400000	$377,199.78	$378,620.27	$1,420.49	0.38%
450000	$424,174.76	$425,772.73	$1,597.97	0.38%
500000	$471,149.74	$472,925.19	$1,775.45	0.38%
550000	$518,124.71	$520,077.64	$1,952.93	0.38%
600000	$565,099.69	$567,230.10	$2,130.41	0.38%
650000	$612,074.67	$614,382.56	$2,307.89	0.38%
700000	$659,049.64	$661,535.01	$2,485.37	0.38%
750000	$706,024.62	$708,687.47	$2,662.85	0.38%
800000	$752,999.59	$755,839.93	$2,840.33	0.38%
850000	$799,974.57	$802,992.38	$3,017.81	0.38%
900000	$846,949.55	$850,144.84	$3,195.29	0.38%
950000	$893,924.52	$897,297.29	$3,372.77	0.38%

First 3 or Less	$1,400.00	$1,400.65	$0.65	0.05%
Over 3 Therms (Nov - Mar)	$0.008760	$0.010040	$0.00128	14.61%
MPDQ Demand Charge	$0.755000	$0.865340	$0.11034	14.61%
Delivery Service Adjustment	$0.000354	$0.000354	$0.00000	0.00%
SBC	$0.000000	$0.000000	$0.00000	0.00%
Merchant Function Charge	$0.022220	$0.020860	($0.00136)	-6.12%
GRT on Delivery	0.000000%	0.000000%	$0.00000	0.00%
GRT on Supply	0.000000%	0.000000%	$0.00000	0.00%
Monthly Cost of Gas Rate	$0.883330	$0.883330	$0.00000	0.00%

Calculation of RDM Targets - Case 08-G-0609

Section 2.2.5
Page 1 of 3

SC 1 Residential Non Heat	**SC1 Res Non Heat**	**SC1 Res Non Heat MB**	**Total SC1 Res Non Heat Target**
Proposed Delivery Revenue	$9,029,551	$1,304,352	$10,333,903
Eliminate Low Income Credits included	$ 270,900	$ 35,550	$ 306,450
Eliminate Low Income Surcharge included	$ (250,315)	$ (32,772)	$ (283,087)
	$ 9,050,136	$ 1,307,130	$ 10,357,266
Number of Customers	32,092	4,202	36,293
RDM Target per Customer			$ 285.38

SC 1 Residential Heat	**SC1 Res Heat**	**SC1 Res Heat MB**	**Total SC1 Res Heat Target**
Proposed Delivery Revenue	$156,217,976	$36,372,407	$192,590,383
Eliminate Low Income Credits included	$ 3,429,450	$ 764,100	$4,193,550
Eliminate Low Income Surcharge included	$ (3,168,697)	$ (706,020)	($3,874,717)
	$ 156,478,729	$36,430,487	$ 192,909,216
Number of Customers	406,243	90,515	496,759
RDM Target per Customer			$ 388.34

SC 2 Residential	**SC2 RNH plus SC2RH**	**SC2 RNH MB plus SC2RH MB**	**Total SC2 Residential**
Proposed Delivery Revenue	$ 555,773	$ 316,256	$ 872,029
Eliminate Low Income Credits included			$ -
Eliminate Low Income Surcharge included	$ (5,205)	$ (1,930)	$ (7,135)
	$ 550,568	$ 314,326	$ 864,894
Number of Customers	667	247	915
RDM Target per Customer			$ 945.50

SC 2 Commercial	**SC2 CNH plus SC2CH**	**SC2 CNH MB plus SC2CH MB**	**Total SC2 Commercial**
Proposed Delivery Revenue	$ 32,006,877.00	$21,377,203	$ 53,384,080
Eliminate Included Economic Dev Discounts	$131,024	$67,137	$198,161
Eliminate Low Income Credits included	$ -	$ -	$ -
Eliminate Low Income Surcharge included	$ (236,580)	$ (104,079)	$ (340,659)
	$ 31,901,321	$21,340,261	$ 53,241,583
Number of Customers	30,331	13,343	43,674
RDM Target per Customer			$ 1,219.06

SC 2 Industrial	**SC2 Ind**	**SC2 Ind MB**	**Total SC2 Industrial**
Proposed Delivery Revenue	$328,182	$202,995	$531,176
Eliminate Included Economic Dev Discounts	$14,343	$6,097	$20,440
Eliminate Low Income Credits included	$ -	$ -	$0
Eliminate Low Income Surcharge included	$ (1,023)	$ (359)	($1,383)
	$ 341,502	$ 208,732	$ 550,234
Number of Customers	131	46	177
RDM Target per Customer			$ 3,104.28

SC 7 Small Volume Firm Transportation	**SC7**		**Total SC7**
Proposed Delivery Revenue	$7,931,130		$7,931,130
Eliminate Included Economic Dev Discounts	$13,516		$13,516
Eliminate Low Income Credits included	$ -		$0
Eliminate Low Income Surcharge included	$ (5,148)		($5,148)
	$ 7,939,498	$ -	$7,939,498
Number of Customers	660		660
RDM Target per Customer			$ 12,029.54

Case 08-G-0609
Illustration of RDM Mechanism

	Rate Year Plan 1
SC 1 Residential Non Heat	
Target Revenue Per Customer	$ 285.38
Actual Number of Customers	38,108
Actual Delivery Revenue w/o MFC	$10,771,557
Average Revenue Per Customer	$ 282.66
RPC Variance (Target - Actual)	2.72
Annual Variance	$103,573
SC 1 Residential Heat	
Target Revenue Per Customer	$ 388.34
Actual Number of Customers	521,597
Actual Delivery Revenue w/o MFC	$201,590,131
Average Revenue Per Customer	$ 386.49
RPC Variance (Target - Actual)	1.85
Annual Variance	$964,546
SC 2 Residential	
Target Revenue Per Customer	$ 945.50
Actual Number of Customers	924
Actual Delivery Revenue w/o MFC	$873,543
Average Revenue Per Customer	$ 945.50
RPC Variance (Target - Actual)	0.00
Annual Variance	$0
SC 2 Commercial	
Target Revenue Per Customer	$ 1,219.06
Actual Number of Customers	45,858
Actual Delivery Revenue w/o MFC	$55,371,246
Average Revenue Per Customer	$ 1,207.45
RPC Variance (Target - Actual)	11.61
Annual Variance	$532,416
SC 2 Industrial	
Target Revenue Per Customer	$ 3,104.28
Actual Number of Customers	168
Actual Delivery Revenue w/o MFC	$533,727
Average Revenue Per Customer	$ 3,169.63
RPC Variance (Target - Actual)	-65.35
Annual Variance	($11,005)
SC 7 Small Volume Firm Transportation	
Target Revenue Per Customer	$ 12,029.54
Actual Number of Customers	667
Actual Delivery Revenue w/o MFC	$7,979,195
Average Revenue Per Customer	$ 11,969.99
RPC Variance (Target - Actual)	59.55
Annual Variance	$39,697
Total Dollars to be collected	$1,629,227

Case 08-G-0609

ILLUSTRATIVE EXAMPLE - SC1 IMPACT ON RDM TARGET OF HEAT/ NON-HEAT RECLASSIFICATION

1) Initial Customer Classification

	No Customers	Rev per Cust Target	Revenues
Heating	496,759	$388.34	$ 192,909,216
Non-Heating	36,293	$285.38	$ 10,357,266
Total	533,052	$381.33	$ 203,266,482

2) Reclassify Heating and Non-Heating Customers

Let: $H = Actual Revenue per Customer of Heating Load
$NH = Actual Revenue per Customer of Non-Heating Load

Heating switch to non-heating	3,000	@ $NH
Non-heating switch to heating	10,000	@ $H

3) After Customers Switch Out

Remaining Heating	493,759	@ $H
Remaining Non-Heating	26,293	@ $NH

(See calculations below for derivation of $H and $NH)

4) End State After Customer Reclassification (@ Actual Aligned Revenue per Customer)

	No Customers	Aligned Rev per Cust Target	Revenues
Heating	503,759	$389.20	$ 196,063,560
Non-Heating	29,293	$245.89	$ 7,202,922
Total	533,052	$381.33	$ 203,266,482

5) Determine Actual Revenue per Customer of Heating Customers ($H) & Non-Heating Customers ($NH)
Use Simultaneous Equations

Eqn 1:

$$\left[493{,}759 \times \$H\right] + \left[3{,}000 \times \$NH\right] = \left[496{,}759 \times \$388\right]$$

$$\mathbf{\$H} = \frac{\$192{,}909{,}216}{493{,}759} - \left[\frac{3{,}000}{493{,}759} \times \$NH\right]$$

$$\mathbf{\$H} = \$390.70 - \left[\$0.01 \times \$NH\right]$$

Eqn 2:

$$\left[26{,}293 \times \$NH\right] + \left[10{,}000 \times \$H\right] = \left[36{,}293 \times \$285\right]$$

$$\mathbf{\$H} = \frac{\$10{,}357{,}266}{10{,}000} - \left[\frac{26{,}293}{10{,}000} \times \$NH\right]$$

$$\mathbf{\$H} = \$1{,}035.73 - \left[\$2.63 \times \$NH\right]$$

Eqn 1 = Eqn 2:

$$\$390.70 - \left[\$0.01 \times \$NH\right] = \$1{,}035.73 - \left[\$2.63 \times \$NH\right]$$

$$\mathbf{\$NH} = \frac{\left[\$1{,}035.73 - \$390.70\right]}{\$2.62}$$

$$\mathbf{\$NH = \$245.89}$$

$$\mathbf{\$H = \$389.20}$$

Note:

Earnings Year 1: The initial customer number and Revenue per Customer targets are included in Step 1. The reclassified number of customers will be determined by March 31, 2010 and will be included in Step 2. The Aligned Revenue per Customer targets will be recalculated based on the formulas in this table and will be shown in Step 4.

Earnings Year 2: The initial customer number in Step 1 remains unchanged. The Revenue per Customer target will change based on Year 2 earnings adjustments and the rate design included in the Joint Proposal. The Aligned Revenue per Customer targets will be recalculated based on the formulas in this table and will be shown in Step. 4.

The Aligned Revenue per Customer targets calculated in Earnings Year 2 will apply in subsequent years.

Case 08-G-0609- Proxy Customer Count Calculation
Variance (%): Minimum Charge Revenue/Minimum Charge versus Number of Customers per RP82SADJ

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Class	Nov-2007	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	TME Oct-2008 Customer Months
SC1 Res Non Heat	1.5%	1.0%	1.0%	1.4%	0.5%	-2.4%	3.2%	-2.0%	1.9%	3.0%	-1.0%	-3.4%	0.4%
SC1 MB Res Non Heat	-2.5%	-6.9%	-5.8%	-4.7%	-4.6%	-5.3%	-2.3%	-3.3%	-2.4%	-0.8%	-5.3%	-5.7%	-4.1%
SC1 Residential Non Heat	1.1%	0.1%	0.2%	0.6%	-0.2%	-2.7%	2.5%	-2.2%	1.3%	2.5%	-1.6%	-3.7%	-0.2%
SC1 Res Heat	1.1%	0.4%	0.8%	1.2%	0.4%	-1.1%	1.0%	-1.3%	1.0%	1.7%	0.0%	-2.3%	0.2%
SC1 MB Res Heat	-1.3%	-5.4%	-4.2%	-3.4%	-2.7%	-3.5%	-1.8%	-1.9%	-1.1%	-0.4%	-3.0%	-4.1%	-2.7%
SC1 Residential Heat	0.8%	-0.5%	0.0%	0.4%	-0.1%	-1.5%	0.5%	-1.4%	0.6%	1.3%	-0.6%	-2.6%	-0.3%
SC2 Res Non Heat	4.6%	-2.1%	2.0%	-1.6%	1.2%	-6.1%	3.0%	-13.4%	7.7%	10.6%	0.0%	-7.9%	-0.2%
SC2 MB Res Non Heat	0.0%	-6.7%	-6.7%	6.7%	-6.3%	-6.3%	6.2%	0.0%	-11.1%	-21.1%	10.5%	-10.0%	-4.0%
SC2 Res Heat	0.3%	-1.6%	2.8%	2.0%	-0.1%	3.3%	0.5%	-1.0%	1.9%	1.6%	-0.9%	-5.1%	0.3%
SC2 MB Res Heat	1.0%	-16.1%	8.8%	-1.5%	-3.3%	-5.5%	0.0%	-5.5%	3.8%	1.9%	-4.2%	-5.0%	-2.1%
SC2 Residential Total	0.8%	-5.0%	4.0%	1.0%	-0.9%	0.2%	0.7%	-3.1%	2.6%	1.8%	-1.4%	-5.4%	-0.4%
SC2 Comm Non Heat	5.3%	0.0%	4.1%	1.6%	-0.4%	-1.3%	2.5%	-2.5%	0.7%	5.8%	0.0%	-5.2%	0.9%
SC2 MB Comm Non Heat	-1.9%	-3.9%	1.1%	-2.3%	-3.2%	-3.9%	0.0%	-4.7%	-1.2%	1.5%	-2.2%	-3.8%	-2.0%
SC2 Comm Heat	0.9%	0.1%	0.7%	1.7%	0.2%	-3.1%	2.0%	-0.2%	1.5%	2.3%	-0.3%	-3.2%	0.2%
SC2 MB Comm Heat	-0.5%	-3.3%	-1.2%	-1.5%	-2.4%	-3.3%	-1.2%	-2.8%	-1.6%	1.8%	-1.5%	-3.3%	-1.7%
SC2 Commercial Total	0.6%	-1.0%	0.3%	0.7%	-0.6%	-3.1%	1.0%	-1.1%	0.5%	2.3%	-0.7%	-3.3%	-0.4%
SC2 Industrial	-1.8%	5.9%	-5.0%	17.5%	-2.4%	2.4%	0.2%	-2.9%	0.9%	0.9%	-0.7%	16.4%	2.5%
SC2 MB Industrial	-7.1%	-15.8%	17.4%	-5.3%	-1.8%	-8.3%	-6.6%	0.0%	-1.7%	3.3%	3.4%	-3.4%	-2.2%
SC2 Industrial Total	-3.4%	-0.6%	1.7%	9.8%	-2.2%	-1.4%	-2.2%	-1.8%	0.0%	1.8%	0.7%	9.7%	0.9%
SC7	0.5%	-0.5%	0.1%	0.2%	-0.2%	-0.5%	-0.2%	-0.3%	-0.6%	-0.5%	0.2%	1.1%	-0.1%
Total Number of Customers	**0.8%**	**-0.5%**	**0.0%**	**0.4%**	**-0.2%**	**-1.7%**	**0.7%**	**-1.5%**	**0.7%**	**1.5%**	**-0.6%**	**-2.8%**	**-0.3%**

Case 08-G-0609- Proxy Customer Count Calculation
Number of Customers = Minimum Charge Revenue Divided by Minimum charge

Class	Nov-2007	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	TME Oct-2008 Customer Months
SC1 Res Non Heat	34,550.7	34,161.2	33,992.8	33,985.0	33,500.2	32,435.5	33,998.8	32,098.7	33,233.2	33,596.5	32,114.1	31,332.6	398,999.4
SC1 MB Res Non Heat	4,060.0	4,082.1	4,312.5	4,532.2	4,662.3	4,705.3	4,937.4	4,939.6	5,040.6	5,212.9	5,105.3	5,182.5	56,772.8
SC1 Residential Non Heat	**38,610.7**	**38,243.2**	**38,305.3**	**38,517.2**	**38,162.5**	**37,140.9**	**38,936.2**	**37,038.4**	**38,273.8**	**38,809.4**	**37,219.4**	**36,515.1**	**455,772.2**
SC1 Res Heat	417,951.0	413,227.8	413,520.4	413,585.6	409,012.8	401,534.8	408,189.9	397,670.7	406,390.6	408,399.5	400,859.9	392,629.5	4,882,972.6
SC1 MB Res Heat	74,808.2	74,544.4	77,739.4	80,571.7	82,640.1	82,836.3	85,247.9	85,363.4	86,368.2	87,961.1	87,010.1	86,921.7	992,012.5
SC1 Residential Heat	**492,759.2**	**487,772.2**	**491,259.8**	**494,157.3**	**491,652.9**	**484,371.1**	**493,437.8**	**483,034.2**	**492,758.8**	**496,360.5**	**487,870.1**	**479,551.2**	**5,874,985.1**
SC2 Res Non Heat	70.1	63.7	65.3	64.9	65.8	62.0	68.0	58.0	70.0	69.7	64.0	58.0	779.4
SC2 MB Res Non Heat	14.0	14.0	14.0	16.0	15.0	15.0	17.0	16.0	16.0	15.0	21.0	18.0	191.0
SC2 Res Heat	582.7	575.8	598.3	586.3	569.4	582.5	565.0	553.5	561.6	560.6	549.1	541.1	6,825.8
SC2 MB Res Heat	191.9	162.0	219.8	201.0	203.0	201.3	211.9	197.5	218.0	217.0	206.0	205.3	2,434.7
SC2 Residential Total	**858.7**	**815.5**	**897.4**	**868.2**	**853.2**	**860.7**	**861.9**	**825.0**	**865.6**	**862.3**	**840.1**	**822.4**	**10,230.9**
SC2 Comm Non Heat	1,782.6	1,688.9	1,758.8	1,702.2	1,654.9	1,633.5	1,685.3	1,586.3	1,634.0	1,717.7	1,601.4	1,526.9	19,972.6
SC2 MB Comm Non Heat	660.3	646.8	681.4	672.0	673.8	666.0	700.8	675.8	706.1	731.7	709.3	687.6	8,211.5
SC2 Comm Heat	29,359.5	29,110.2	29,201.3	29,421.9	28,786.2	27,551.6	28,688.4	27,722.1	27,997.3	28,110.6	27,389.8	26,779.3	340,118.3
SC2 MB Comm Heat	12,276.2	12,125.4	12,489.0	12,606.4	12,647.8	12,638.9	13,011.6	12,915.4	13,125.4	13,640.6	13,271.9	13,090.7	153,839.3
SC2 Commercial Total	**44,078.5**	**43,571.3**	**44,130.5**	**44,402.5**	**43,762.7**	**42,490.1**	**44,086.2**	**42,899.6**	**43,462.9**	**44,200.7**	**42,972.3**	**42,084.5**	**522,141.8**
SC2 Industrial	130.6	139.8	126.4	129.3	109.3	111.6	108.2	104.9	109.9	111.0	109.2	132.7	1,422.9
SC2 MB Industrial	52.0	48.0	65.8	54.0	56.0	55.0	57.0	60.0	59.0	62.0	61.0	56.0	685.8
SC2 Industrial Total	**182.6**	**187.8**	**192.2**	**183.3**	**165.3**	**166.6**	**165.2**	**164.9**	**168.9**	**173.0**	**170.2**	**188.7**	**2,108.7**
SC7	**662.1**	**656.0**	**661.7**	**660.0**	**659.0**	**661.0**	**667.0**	**668.0**	**666.7**	**669.4**	**675.3**	**680.2**	**7,986.4**
Total	**577,151.9**	**571,246.0**	**575,446.8**	**578,788.6**	**575,255.6**	**565,690.4**	**578,154.3**	**564,630.0**	**576,196.8**	**581,075.3**	**569,747.4**	**559,842.1**	**6,873,225.1**

Case 08-G-0609- Proxy Customer Count Calculation
Number of Customers Per RP82Sadj Report

Class	Nov-2007	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	TME Oct-2008 Customer Months
SC1 Res Non Heat	34,040	33,828	33,646	33,515	33,340	33,222	32,945	32,763	32,616	32,607	32,441	32,422	397,385
SC1 MB Res Non Heat	4,166	4,384	4,577	4,754	4,888	4,969	5,052	5,106	5,167	5,254	5,391	5,498	59,206
SC1 Residential Non Heat	**38,206**	**38,212**	**38,223**	**38,269**	**38,228**	**38,191**	**37,997**	**37,869**	**37,783**	**37,861**	**37,832**	**37,920**	**456,591**
SC1 Res Heat	413,217	411,437	410,294	408,796	407,305	406,016	404,175	403,084	402,328	401,607	400,971	401,951	4,871,181
SC1 MB Res Heat	75,767	78,798	81,165	83,391	84,920	85,831	86,789	87,031	87,359	88,278	89,721	90,601	1,019,651
SC1 Residential Heat	**488,984**	**490,235**	**491,459**	**492,187**	**492,225**	**491,847**	**490,964**	**490,115**	**489,687**	**489,885**	**490,692**	**492,552**	**5,890,832**
SC2 Res Non Heat	67	65	64	66	65	66	66	67	65	63	64	63	781
SC2 MB Res Non Heat	14	15	15	15	16	16	16	16	18	19	19	20	199
SC2 Res Heat	581	585	582	575	570	564	562	559	551	552	554	570	6,805
SC2 MB Res Heat	190	193	202	204	210	213	212	209	210	213	215	216	2,487
SC2 Residential Total	**852**	**858**	**863**	**860**	**861**	**859**	**856**	**851**	**844**	**847**	**852**	**869**	**10,272**
SC2 Comm Non Heat	1,693	1,689	1,690	1,675	1,661	1,655	1,644	1,627	1,623	1,623	1,601	1,610	19,791
SC2 MB Comm Non Heat	673	673	674	688	696	693	701	709	715	721	725	715	8,383
SC2 Comm Heat	29,111	29,087	29,006	28,928	28,730	28,427	28,126	27,774	27,583	27,490	27,461	27,677	339,400
SC2 MB Comm Heat	12,332	12,543	12,646	12,798	12,958	13,076	13,176	13,287	13,333	13,394	13,468	13,534	156,545
SC2 Commercial Total	**43,809**	**43,992**	**44,016**	**44,089**	**44,045**	**43,851**	**43,647**	**43,397**	**43,254**	**43,228**	**43,255**	**43,536**	**524,119**
SC2 Industrial	133	132	133	110	112	109	108	108	109	110	110	114	1,388
SC2 MB Industrial	56	57	56	57	57	60	61	60	60	60	59	58	701
SC2 Industrial Total	**189**	**189**	**189**	**167**	**169**	**169**	**169**	**168**	**169**	**170**	**169**	**172**	**2,089**
SC7	**659**	**659**	**661**	**659**	**660**	**664**	**668**	**670**	**671**	**673**	**674**	**673**	**7,991**
Total Number of Customers	**572,699**	**574,145**	**575,411**	**576,231**	**576,188**	**575,581**	**574,301**	**573,070**	**572,408**	**572,664**	**573,474**	**575,722**	**6,891,894**

Case 08-G-0609- Proxy Customer Count Calculation
Minimum Charge Revenue by Service Classification (RP200S)

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Class	Nov-2007	Dec-2007	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	TME Oct-2008
SC1 Res Non Heat	$ 508,241.01	$ 502,510.60	$ 500,033.40	$ 499,919.94	$ 492,788.34	$ 477,126.56	$ 500,122.17	$ 472,172.60	$ 488,860.60	$ 494,204.96	$ 472,398.10	$ 460,903.28	$ 5,869,281.56
SC1 MB Res Non Heat	$ 59,722.69	$ 60,047.20	$ 63,437.40	$ 66,668.69	$ 68,581.99	$ 69,215.55	$ 72,629.47	$ 72,661.98	$ 74,147.53	$ 76,681.82	$ 75,098.93	$ 76,234.26	$ 835,127.51
SC1 Residential Non Heat	**$ 567,963.70**	**$ 562,557.80**	**$ 563,470.80**	**$ 566,588.63**	**$ 561,370.33**	**$ 546,342.11**	**$ 572,751.64**	**$ 544,834.58**	**$ 563,008.13**	**$ 570,886.78**	**$ 547,497.03**	**$ 537,137.54**	**$ 6,704,409.07**
SC1 Res Heat	$ 6,148,059.93	$ 6,078,581.32	$ 6,082,884.81	$ 6,083,844.00	$ 6,016,578.15	$ 5,906,577.03	$ 6,004,473.94	$ 5,849,736.73	$ 5,978,005.83	$ 6,007,556.02	$ 5,896,649.65	$ 5,775,579.36	$ 71,828,526.77
SC1 MB Res Heat	$ 1,100,428.59	$ 1,096,547.58	$ 1,143,546.17	$ 1,185,210.35	$ 1,215,635.48	$ 1,218,522.48	$ 1,253,996.20	$ 1,255,695.71	$ 1,270,475.62	$ 1,293,907.55	$ 1,279,919.17	$ 1,278,618.92	$ 14,592,503.82
SC1 Residential Heat	**$ 7,248,488.52**	**$ 7,175,128.90**	**$ 7,226,430.98**	**$ 7,269,054.35**	**$ 7,232,213.63**	**$ 7,125,099.51**	**$ 7,258,470.14**	**$ 7,105,432.44**	**$ 7,248,481.45**	**$ 7,301,463.57**	**$ 7,176,568.82**	**$ 7,054,198.28**	**$ 86,421,030.59**
SC2 Res Non Heat	$ 1,355.80	$ 1,231.94	$ 1,262.92	$ 1,256.46	$ 1,273.23	$ 1,199.70	$ 1,315.80	$ 1,122.30	$ 1,354.50	$ 1,348.70	$ 1,238.40	$ 1,122.30	$ 15,082.05
SC2 MB Res Non Heat	$ 270.90	$ 270.90	$ 270.90	$ 309.60	$ 290.25	$ 290.25	$ 328.95	$ 309.60	$ 309.60	$ 290.25	$ 406.35	$ 348.30	$ 3,695.85
SC2 Res Heat	$ 11,275.28	$ 11,141.77	$ 11,577.11	$ 11,345.10	$ 11,017.29	$ 11,270.75	$ 10,932.30	$ 10,709.45	$ 10,867.62	$ 10,847.65	$ 10,625.10	$ 10,470.29	$ 132,079.71
SC2 MB Res Heat	$ 3,713.27	$ 3,134.70	$ 4,253.13	$ 3,889.35	$ 3,928.05	$ 3,894.52	$ 4,100.92	$ 3,821.63	$ 4,218.30	$ 4,198.95	$ 3,986.10	$ 3,972.28	$ 47,111.20
SC2 Residential Total	**$ 16,615.25**	**$ 15,779.31**	**$ 17,364.06**	**$ 16,800.51**	**$ 16,508.82**	**$ 16,655.22**	**$ 16,677.97**	**$ 15,962.98**	**$ 16,750.02**	**$ 16,685.55**	**$ 16,255.95**	**$ 15,913.17**	**$ 197,968.81**
SC2 Comm Non Heat	$ 34,493.98	$ 32,680.82	$ 34,032.76	$ 32,936.98	$ 32,022.34	$ 31,608.56	$ 32,610.00	$ 30,694.72	$ 31,618.57	$ 33,238.43	$ 30,987.02	$ 29,545.90	$ 386,470.08
SC2 MB Comm Non Heat	$ 12,776.17	$ 12,514.94	$ 13,185.10	$ 13,003.20	$ 13,038.67	$ 12,887.74	$ 13,560.50	$ 13,076.07	$ 13,663.01	$ 14,157.76	$ 13,724.32	$ 13,305.04	$ 158,892.52
SC2 Comm Heat	$ 568,106.17	$ 563,283.10	$ 565,044.93	$ 569,314.34	$ 557,012.64	$ 533,123.40	$ 555,121.41	$ 536,422.94	$ 541,748.56	$ 543,940.66	$ 529,992.18	$ 518,179.74	$ 6,581,290.07
SC2 MB Comm Heat	$ 237,543.53	$ 234,625.98	$ 241,661.65	$ 243,934.42	$ 244,735.32	$ 244,563.40	$ 251,775.33	$ 249,912.62	$ 253,977.08	$ 263,946.32	$ 256,810.84	$ 253,304.55	$ 2,976,791.04
SC2 Commercial Total	**$ 852,919.85**	**$ 843,104.84**	**$ 853,924.44**	**$ 859,188.94**	**$ 846,808.97**	**$ 822,183.10**	**$ 853,067.24**	**$ 830,106.35**	**$ 841,007.22**	**$ 855,283.17**	**$ 831,514.36**	**$ 814,335.23**	**$ 10,103,443.71**
SC2 Industrial	$ 2,527.11	$ 2,705.14	$ 2,445.84	$ 2,501.96	$ 2,114.96	$ 2,158.80	$ 2,094.30	$ 2,029.83	$ 2,127.22	$ 2,147.85	$ 2,113.02	$ 2,567.76	$ 27,533.79
SC2 MB Industrial	$ 1,006.20	$ 928.80	$ 1,272.59	$ 1,044.90	$ 1,083.60	$ 1,064.25	$ 1,102.95	$ 1,161.00	$ 1,141.65	$ 1,199.70	$ 1,180.35	$ 1,083.60	$ 13,269.59
SC2 Industrial Total	**$ 3,533.31**	**$ 3,633.94**	**$ 3,718.43**	**$ 3,546.86**	**$ 3,198.56**	**$ 3,223.05**	**$ 3,197.25**	**$ 3,190.83**	**$ 3,268.87**	**$ 3,347.55**	**$ 3,293.37**	**$ 3,651.36**	**$ 40,803.38**
SC7	**$ 200,815.23**	**$ 198,964.80**	**$ 200,703.62**	**$ 200,178.00**	**$ 199,874.70**	**$ 200,481.30**	**$ 202,291.09**	**$ 202,604.40**	**$ 202,220.12**	**$ 203,019.01**	**$ 204,818.49**	**$ 206,304.66**	**$ 2,422,275.42**
Total	**$ 8,890,335.86**	**$ 8,799,169.59**	**$ 8,865,612.33**	**$ 8,915,357.29**	**$ 8,859,975.01**	**$ 8,713,984.29**	**$ 8,906,455.33**	**$ 8,702,131.58**	**$ 8,874,735.81**	**$ 8,950,685.63**	**$ 8,779,948.02**	**$ 8,631,540.24**	**$ 105,889,930.98**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
PSC Case No. 08-G-0609

Operating Property Taxes (excludes Non-Operating)
($000's)

Rate Plan Year 2 Update to be provided to PSC Staff no later than February 26, 2010

I GAS RATE ALLOWANCE

cols:		A	B	C	D	E	F	G	H
								EXAMPLE	EXAMPLE
								Rate Plan Year 2	**Rate Plan Year 2**
								21.49%	**1.49%**
EXAMPLE				Most Recent Actual paid (1) TOTAL Taxes	# months (3) to Inflate	@ -0.0017 Inflation (4)	Most Recent paid w/ Inflation TOTAL Taxes	Gas Rate Allowance Rate Year Ending **May 19, 2011**	Electric Deferral @ **May 19, 2011**
			Calendar Yr						
Example	County		2010	$ 48,000	5	$ (34)	$ 47,966		
Example	Village		2009	$ 4,000	17	(10)	3,990		
Example	City		2009	$ 19,000	17	(46)	18,954		
Example	School		2009	$ 96,000	17	(231)	95,769		
Example	Total			$ 167,000		$ (321)	$ 166,679	$ 35,819	

II ELECTRIC DEFERRAL The Company agreed to defer 1.49% of Total Oper.Property Taxes from the Electric business in Year 2. $ (2,484)

Beyond May 19, 2011 (in the event of a Stay-out)

III GAS RATE ALLOWANCE - remains frozen.

IV ELECTRIC DEFERRAL - continues, but the amount remains the same as the amount determined in Rate Plan Year 2 (i.e. $2,484 in the example above) until either Electric or Gas rates are reestablished. As noted above, when recording the deferral monthly, May will have to be pro-rated based on number of days.

Notes:

1. Update of most recent TOTAL (Electric and Gas) Operating Property Taxes to be provided by the NM Property Tax Dept.
2. Per 2 year Gas rate Settlement, the Company agreed to set the 2nd year Gas rate allowance at 21.49% of Total Operating Property Taxes. The Company will record on its books the electric / gas taxes per the best information available to the NM Property Tax Dept.
3. number of months to which the inflation rate is applicable - actual 2010 taxes need 5 months of inflation for 2011 (Jan-May). Actual 2009 taxes need 17 months, all of 2010 + Jan-May 2011. This method is consistent with using a 5-Year Calendar Year average inflation rate.
4. Inflation amount = 5 year average rate (below) x # months applicable for that type of tax.

Operating Property Taxes (excludes Non-Operating)
5 Year Average Change

Annual Inflation (Agreed to in this Settlement to be 5 year average)

(whole $)

	Calendar Yr	Total (E+G) Operating Property Taxes per books	Electric Operating Property Taxes per books	Gas Operating Property Taxes per books	**TOTAL Year Over Year %** (GRW-4 method)	Rate Plan Yr 2
Example	2009	166,000,000	130,000,000	36,000,000		2.20%
Actual	2008	162,431,883	127,186,577	35,245,306		0.90%
Actual	2007	160,983,033	128,787,223	32,195,810	-1.26%	-1.26%
Actual	2006	163,044,417	130,437,053	32,607,364	-5.44%	-5.44%
Actual	2005	172,431,070	137,969,262	34,461,808	2.77%	2.77%
Actual	2004	167,784,967	134,319,511	33,465,456	4.18%	
Actual	2003	161,047,489	128,591,081	32,456,408	7.11%	
Actual	2002	150,357,585	120,438,836	29,918,749		
					7.36%	-0.83%
				5 year average	1.47%	**-0.17%**
						Example

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
PSC Case No. 08-G-0609

Stay-out Premium
Deferral in the Event Joint Proposal Section 2.3.3 is applicable
($000's)

Example 1: Company files for new NM Gas rates that go into effect September 1, 2010.
The Company would be required to defer for customers; benefit, the following amount of the Stay-out Premium:

	($000's)
All of Rate Plan Year One (May20, 2009 - May 19, 2010) premium	$ (1,589)
May 20, 2010 through August 31, 2010 = (12/31 x 7.97% + 6.27% + 5.16% + 4.90%) x $1,589	(309)
Total amount to be deferred	$ (1,898)

Example 2: Company files for new NM Gas rates that go into effect November 21, 2010.
The Company would be required to defer for customers; benefit, the following amount of the Stay-out Premium:

	($000's)
All of Rate Plan Year One (May20, 2009 - May 19, 2010) premium	$ (1,589)
May 20, 2010 through November 20, 2010 = (12/31 x 7.97% + 6.27% + 5.16% + 4.90% + 5.38% + 7.13% + (20/30 x 8.81%)) x $1,589	(601)
Total amount to be deferred	$ (2,190)

	# days	Gas Delivery Revenue % by month
April	30	9.69%
May	31	7.97%
June	30	6.27%
July	31	5.16%
August	31	4.90%
September	30	5.38%
October	31	7.13%
November	30	8.81%
December	31	10.45%
January	31	11.57%
February	28	11.56%
March	31	11.11%
	365	100.00%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)

Gas Earnings Review - Individual Years for limiting specific Deferrals AND Earnings Sharing based on 2 Year Cumulative ROE

(Million Dollars)

The following sections of the Joint Proposal further describe specific Gas Deferrals that are limited to the extent the Company is not over-earning:

Section 4.2.1 Regulatory, Legislaive and Accounting Changes; Section 4.4.6 NYSERDA Auction Rate Debt; Section 4.4.4 Cost of the Low Income Program; Section 4.4.7 New Long-Term Debt Issuances; and Section 4.4.8 PSC Assessment

Joint Proposal Section 3.1 Earnings Report: two year cumulative earnings comparison will be to 11.35% (10.2% + 115 basis pts) ROE.

For simplification, the Earnings Sharing review will be applicable to an "Earnings Year" period June 1, 2009 through May 31, 2011 (even though the actual Rate Plan Years begin May 20).

Any excess earnings adjustments will be excluded from subsequent sharing.

The measure fpr a partial year will be the cumulative result of the two preceding years plus the partial year.

Line	**($ Millions)**	Two Year Gas Settlement		EXAMPLES In the Event of a Stay-out				
		Year 1	Year 2	Year 3	Year 4	Partial Yr 5		
	Individual Years Earnings Year:	TME May 31, 2010	TME May 31, 2011	TME May 31, 2012	TME May 31, 2013	Jun 1, -Oct 31 (Assumes New Rates Eff Nov 15, 2013)	<-- nearest full month end to effective date of new rates (Nov 15 in this example)	
	Current Year = 1							EXAMPLE
1								Partial Year
2						5 mo avg (Jun-Oct)		Threshold Calc
3	Actual Common Equity (Parent Company)	$ 325.0	$ 375.0	$ 425.0	$ 475.0	$ 450.0	Settlement Operating Income After Tax (App A)	$ 79,252
4							% Oper Rev (per App x) for Stub period (Jun-Oct)	28.84%
5	ROE's filed in Earnings Reports to the PSC for each resp. year	9.50%	10.00%	13.50%	18.00%	9.00%	Settlement Stub year pro-rated Oper Income After Tax	$ 22,857
6	Subsequent minor revisions (see latest Earnings filing)	0.00%	0.00%	0.00%	0.00%	0.00%	Settlement Rate Base prorated ($1,029,252 x 5/12)	$ 428,855
7	Actual ROE used in this filing	9.50%	10.00%	13.50%	18.00%	9.00%	Stub period ROR on Rate Base	5.3%
8							Settlement WACC less CE - App A (7.70% - 4.46%) x 5/12	1.35%
9	Actual (calculated) Net Income for CE	$ 30.9	$ 37.5	$ 57.4	$ 85.5	$ 40.5	Settlement CE captial % (App A)	43.70%
10							Settlement Stub period ROE plus prorated 5/12 of 115 pts	9.59%
11	ROE Sharing threshold (per JP Section 3.5)	11.35%	11.35%	11.35%	11.35%	9.59%	<-- Stub period threshold is calculated as shown here --------------------------------	▲
12								
13								

Line	Individual Years Under Earning Amount - this section used only as a limitation to certain Gas Deferrals, NOT for purposes of Earnings Sharing		Year 1	Year 2	Year 3	Year 4	Partial Yr 5
15	ROE Deficiency from the % in rates	10.20%	0.70%	0.20%	Over Earned	Over Earned	1.20%
16	After-tax Earnings Deficiency		$ 2.275	$ 0.750	n/a	n/a	$ 5.400
17	Combined Federal & State Income Tax Rate		39.615%	39.615%	39.615%	39.615%	39.615%
18	Pre-tax Deferral maximum (for sum of applicable Gas Deferrals)		$ 3.767	$ 1.242	$ - 0 -	$ - 0 -	$ 8.943
19							
20							

21 **Earnings Sharing calculation - Two Year Average ROE and Deferral if applicable**

22 **(note: in the case of a partial "Stub" year, the average ROE shall be the Stub period plus the 2 prior years**

Line		Average Years 1-2	Average Years 2-3	Average Years 3-4	Average Years 3-4 + Stub
26	Earnings Sharing Report is due by	08/31/11	08/31/12	08/31/13	(Within 90 days)
27	Actual Cumulative Net Income	$ 68.4	$ 94.9	$ 142.9	$ 183.4
28	Adjustment to exclude amounts previously in excess of Earnings threshold	$ -	$ -	$ (4.1)	$ (40.8)
29	Adjusted Cumulative Net Income	$ 68.4	$ 94.9	$ 138.8	$ 142.7
30	Average Net Income	$ 34.2	$ 47.5	$ 69.4	$ 47.6
31	Average Actual Common Equity (after exclusion of Goodwill)	$ 350.0	$ 400.0	$ 450.0	$ 450.0
32	**Average Actual ROE (Avg Net Income / Avg Equity)**	9.77%	11.86%	15.42%	10.57%
33	ROE Threshold (weighted avg)	11.35%	11.35%	11.35%	10.76%
34	Difference	-1.58%	0.51%	4.07%	-0.20%
35	Cumulative Actual Common Equity	$ 700.0	$ 800.0	$ 900.0	$ 450.0
36	After-tax Earnings Between Threshold and 13.6%	$ -	$ 4.1	$ 20.3	$ -
37	After-tax Earnings Between 13.61% and 15.6%	$ -	$ -	$ 16.4	$ -
38	After-tax Earnings Over 15.6%	$ -	$ -	$ -	$ -
39	Deferral of 50% of amount Between Threshold and 13.6%, for benefit of Customers	$ -	$ 2.1	$ 10.1	$ -
40	Deferral of 75% of amount Between 13.61% and 15.6%, for benefit of Customers	$ -	$ -	$ 12.3	$ -
41	Deferral of 90% of amount Over 15.6%	$ -	$ -	$ -	$ -
42	Total Deferral for benefit of Customers (after-tax $)	$ -	$ 2.1	$ 22.4	$ -
43	Combined Federal & State Income Tax Rate	39.615%	39.615%	39.615%	39.615%
44	Total Deferral grossed up for income taxes (pre-tax $)	$ -	$ 2.9	$ 31.3	$ -

1 For Earnings Reporting purposes, the following adjustments should be made to book Net Income:
2 a) New: beginning with Earnings Year 1, Gas Property Taxes per books will be adjusted to reflect 21.49% of Total Operating Property Taxes
b) Gas O&M exp per books, excluding Bad Debts, will be adjusted to reflect 17.0% ot Total O&M exp excluding Bad Debts, SBC & RPS exp
c)
3 Actual ROE calculation will use Parent Capital structure as described in JP section 3.2
5 Original ROE's annual Gas earnings filings for respective periods
6 Impacts of ROE revisions shown in filing support (discovered after original filings)
7 Actual ROE used in the earnings sharing calculation
9 Line 7 x Line 3 (ROE x CE)
11 JP Section 3.5
15 10.2% ROE (basis for rates) - line 7
16 Line 15 x line 3
17 Federal tax rate 35.0%, NYS 7.1%
18 line 16 / (1-line 17)
27 sum of appropriate years line 9
28 sum of prior sharing period lines 36,37 & 38
29 line 27 + line 28
30 line 29 / 2
31 average appropriate years line 3
32 line 30 / line 31
33 weighted average of line 11
34 line 32 - line 33
35 sum of appropriate years line 3
36 Line 32 Between Cap and 13.6% * Line 35
37 Line 32 Between 13.61% and 15.6% * Line 35
38 Line 32 Greater than 15.6% * Line 35
39 Line 36 * 50%
40 Line 37 * 75%
41 Line 38 * 90%
42 Line 39 + Line 40 + Line 41
43 Federal rate 35.0% and NYS 7.1%
44 Line 42 * (1+ Line 43)

Appendix L1

Included in this Appendix are:

1. Excerpts from PSC Request DAG-46 (filed in this Gas case)
2. Excerpts from PSC Request 354 Gerbsch (DAG-41) Supplemental (filed in the Second CTC Reset Compliance filing)
3. PSC Request RAV-8 (filed in this Gas case)
4. Excerpts from the March 22, 2007 Settlement Stipulation (Cae 01-M-0075), including Attachments 4 and 5 and the April 17, 2007 Errata notice.

Forecast P&OPEB Revenue Requirement

The first three references above support the development of Rate Plan Year 1 P&OPEB revenue requirement, and provide the methodology for developing a similar Rate Plan Year 2 revenue requirement. Note, the Niagara Mohawk capitalization rate used for Rate Plan Year 1, and to be used in the development of Rate Plan Year 2 forecast P&OPEB, was derived as follows:

Forecasted Capitalization Rate - Used in Setting RYE 3/2010 Gas Rates

1) HY % for Regular Capitalization per DAG-20	28.6300%
2) 3rd Party / Associated Company Capitalization Credits DAG-41	2.1116%
3) Additional Capitalization Adjustment per Gas Joint Proposal	.7986%
Total Capitalization Rate	31.5402%

Along with the capitalization rate shown above, the following will be used in developing the Rate Plan Year two (Year Ending May 19, 2011) P&OPEB revenue requirement:

- Most recent fiscal year ending March 31 actuarial study of Niagara Mohawk and Service Company P&OPEB
- Service Company allocation rate to Niagara Mohawk of 25.76% (same as first year)
- Niagara Mohawk electric / gas allocations of 83% / 17% respectively
- Elimination of costs related to four Consumer Advocates (ref. RAV-8)

Actual P&OPEB Revenue Requirement

The following section, as well as Attachments 4 from the March Settlement Stipulation, and the related Errata notice, are guidance for the calculation of an actual capitalization rate, and an actual Service Company allocation rate to be used when developing actual P&OPEB expense. Attachment 5 from the March Settlement Stipulation provides guidance on the determination of a credit adjustment for the transfer of employees to the Service Company.

<u>Actual Capitalization of Pension and OPEB Costs</u>

For the gas department, the percentage of pension and OPEB costs to be capitalized shall be determined as follows:

1. The Company shall calculate a capitalization rate at the beginning of each fiscal year using the actuarial estimates of pension and OPEB expenses for the year, along with all other fringe benefit costs subject to capitalization, and will adjust this rate for updated actuarial and other estimates provided in September of each year. The rate may also be adjusted at other times throughout the year if there is a fluctuation in the rate of greater than +/- 20 percent.

2. After the close of each fiscal year, the Company shall compare the amount of fringe benefits (including pension and OPEB costs), payroll taxes and workers compensation actually capitalized on the books, to the amount capitalized resulting from the methodology established in its response to Information Request PSC-276 in Case No. 01-M-0075. Based on the results of this annual reconciliation, the Company will adjust the amount capitalized associated with fringe benefits (which includes, but is not limited to pension and OPEBs). In addition, the Company will adjust the applicable pension and OPEB deferral accounts to reflect the capitalized pension and OPEB costs determined pursuant to the methodology set forth in the same Information Request response.

3. Attachment 4, Table 1 illustrates the method that will be used for the annual reconciliation described in paragraph 2, above. Attachment 4, Table 2 includes payroll information supporting the calculation on Table 1.

Journal Entry Details

Monthly Deferral:

Pursuant to Attachment 16 of the Merger Joint Proposal in C. 01-M-0075 and supplemented by this Gas Joint Proposal in C. 08-G-0609, actual gas pension and OPEB expense comprise the following:

1) Expense booked directly by the Company pursuant to FAS 87 or FAS 106, derived from actuarial reports, excluding the costs (a) associated with the four additional consumer advocates (per the May 14, 2007 Settlement letter, and as calculated in RAV-8 in Case 08-G-0609), and (b) any separation of early retirement costs.
2) Amortization of the regulatory asset "Unrecognized Pension Loss" or "Unrecognized OPEB Loss" created by the fair value adjustment.
3) Pension/OPEB expense allocated from the Service Company. The amount allocated from the Service Company is reduced by any SERP-related amounts as directed in Attachment 16.
4) A reduction to pension/OPEB expense for the amount capitalized will include credits for the normal capitalization of payroll, and for third party and associated company billing revenues . The amount of normal capitalization of payroll will be determined based upon the process described above, and will be subject to adjustment annually based on a reconciliation as shown in Table 1. Third party and intercompany billing pension and OPEB revenue will be as actually realized and not subject to this annual reconciliation. *note: the language in #4 above uses the April 17, 2007 Errata notice.*
5) The allocation between electric and gas operations for items (1) through (4) above is 83% to electric and 17% to gas.
6) The sales unit variation adjustment as required per the Statement of Policy on Pensions/OPEBs, C. 91-M-0890.

Monthly, the sum of the elements noted above are compared against a pre-established level of pension/OPEB expense, as per Joint Proposal Section 4.1.1 for Rate Plan Year One, and Section 2.3.1.2 for Rate Plan Year Two. The Company will take the annual pre-established level of pension/OPEBs expense amounts and divide them by twelve in order to perform a monthly reconciliation. The amount above or below the threshold is the amount deferred monthly. Separate entries are recorded for the pension and OPEB deferrals:

Pension Deferral Account:	FERC 182561Deferred Pension Costs - Gas
OPEB Deferral Account:	FERC 182562Deferred OPEB Costs - Gas
Pension Expense Account:	FERC 926000, Employee Pensions and Benefits, Activity AG1060
OPEB Expense Account:	FERC 926000, Employee Pensions and Benefits, Activity AG1070

Annual Reconciliation Adjustment:

An adjusting entry will be made annually, but no later than May of the subsequent fiscal year, for the reconciliation of fringe benefits capitalized to the amount to be capitalized pursuant to PSC-276 as discussed above. The entry for the reconciliation adjustment, based on the illustration included in Table 1 is as follows:

O&M Accounts	$2,400,748	
Capital Accounts		$2,400,748
Deferral Accounts	$1,707,741	
O&M Accounts		$1, 707,741

Determination of Credit for Transfer of Employees to Service Company (Attachment 5)

Section 3.8.2 of the Deferral Audit Stipulation in C. 01-M-0075 (dated March 22, 2007) relates to the required annual adjustment to be made to pension and OPEB expense to account for employees who transferred to or from National Grid USA Service Company, Inc. (Service Company) throughout the year. This Joint Proposal in C. 08-G-0609 does not modify this required annual adjustment. As detailed in Attachment 5 to the Deferral Audit Stipulation:

After the close of each fiscal year, the Company shall: (1) identify all employees who transferred from Niagara Mohawk to the Service Company or from the Service Company to Niagara Mohawk during the fiscal year; and (2) making the hypothetical assumption that all employee transfers occurred on January 1 of the fiscal year, calculate the difference in pension and OPEB expense allocated between Niagara Mohawk and the Service Company for (a) the capitalized portion of pension and OPEB expense; and (b) the company's share of the monthly Service Company allocation. This adjustment for (b), above, shall be subject to Niagara Mohawk's ability to provide support to Staff that the annual pension and OPEB costs for Service Company are derived from actuarial estimates of Service Company pension and OPEB expenses for the year. The revised valuations as of January 1 will be provided by the Company's actuaries. The credit determination, if any, resulting from this Attachment 5 shall follow the determination set forth in the preceding Attachment 4.

An example calculation of the adjustment described above will be applicable from April 2006 forward and is presented in Attachment 5, Table 1.

Excerpts from
PSC Request DAG-46
This Gas Case 08-G-0609

Date of Request 9-19-08

Request No. DAG-46
NMPC Req. No. NM 377 DPS-368 DAG-46

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid
Case 08-G-0609 Gas Rate Case
Request for Information

FROM: Denise Gerbsch

Request: Revised Pension/OPEBs estimates per Hewitt
In DAG-11 of the current gas rate case, the company provided attachments containing actuary estimates dated 3/5/2008 from Hewitt for Pensions/OPEBs for actual FYE 3/2008, and estimates for FYE 3/2009, 3/2010, 3/2011, 3/2012 and 3/2013.
In the Company's 9/12/2008 response to PSC-354 in the CTC Reset Case (C. 01-M-0075), an attachment was provided containing the revised actuary projections dated 9/5/2008 from Hewitt for Pensions/OPEBs for actual FYE 3/2009, and estimates for FYE 3/2010, 3/2011, 3/2012, 3/2013 and 3/2014.

Based on the documents provided by the Company in response to both DAG-11 and PSC-354, attached are staff calculations for the RYE 3/2010 pension and OPEBs forecast expense and deferral balances. These calculations represent the use of Hewitt's actual FYE 3/2008, actual FYE 3/2009 and revised projection for the RYE 3/2010, the Company's updated capitalization rate as per a company recommended adjustment in response to DAG-41, with no other Company assumptions modified.

Please review staff calculations, and indicate an agreement or disagreement with the calculations and the amounts contained in the schedules. If the Company disagrees, please provide (a) updated schedules for RYE 3/2010 pension and OPEBs expense, (b) updated schedules for the forecasted pensions and OPEBs deferral balances as of 3/31/2009, and (c) all supporting workpapers and documentation for the Company's calculations.

Response:
The Company agrees with the calculations provided by staff on the calculation of the Rate Year Pension and OPEB expenses. However, the Company believes that the Pension and OPEB deferral calculation needs to be adjusted to reflect only 25% of the OPEB service company costs for calendar year 2009 and adjust the additional month for both the OPEB and pension deferrals to be one third of the quarterly amount rather than one twelfth of the quarterly amount. In addition, the Company believes the amounts for the Service Company pension per the Staffs calculation should be $138,077 for FY 2009 rather than -$1,727,571. Please see attached revision.

Name of Respondent:	Date of Reply:
James Molloy	September 29, 2008

Form 103

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Operating Expenses by Component
FAS 106 - Other Post Employment Benefits (OPEB) Expense Type B01 - September 5, 2008 UPDATE

Staff Calculations

	Filed 4/2009-3/2010	Revised Sept 05 Forecast 4/2009-3/2010	Variance Revised over/(under) Filed
1 OPEB New Reg Amortization	5,680,890.00	5,728,662.89	47,772.89
2 OPEB - Expense	15,855,373.06	16,360,800.00	505,426.94
3 Less: Amount Capitalized	(6,165,832.12)	(6,790,654.32)	(624,822.21)
4 Service Co Allocation	836,579.64	973,423.46	136,843.83
5 Total Gas OPEB Expense	16,207,010.59	16,272,232.03	65,221.44
6 Rate Allowance	15,500,000.00	16,272,232.03	772,232.03
Rate Allowance less Gas OPEB Expense			707,010.59

Notes:

Capital Percent	30.7416%
Service Payroll Charged to NIMO	25.76%

September 5, 2008 Version

Calculation of NIMO OPEB Year Ended	3/31/2008	3/31/2009	3/31/2010	3/31/2011	3/31/2012	
1 FAS 106 OPEB Cost Page 40 & 43	$ 104,939,330	$ 115,431,262	$ 108,203,000	$ 102,743,000	$ 99,555,000	
2 Regulatory Expense Page 39	$ (11,962,796)	$ (11,962,796)	$ (11,963,000)	$ (11,963,000)	$ (11,963,000)	
3 Line 1 + Line 2	$ 92,976,534	$ 103,468,466	$ 96,240,000	$ 90,780,000	$ 87,592,000	
4 One Time FAS 106 Expense Page 39	$ (316,000)	$ (292,000)	$ (243,000)	$ (122,000)		
5 Line 17	30.2674%	30.2674%	30.2674%	30.2674%		
6 Line 4 * Line 5	$ (95,645)	$ (88,381)	$ (73,550)	$ (36,926)		
7 Line 3 + Line 6	$ 92,880,889	$ 103,380,085	$ 96,166,450	$ 90,743,074	$ 87,592,000	$ 470,762,498
8 Regulatory Expense Page 39 & 43	$ 33,417,000	$ 33,417,000	$ 33,698,017	$ 33,417,000	$ 25,062,750	$ 159,011,767
9 FAS 106 OPEB Cost Page 40	$ 5,399,472	$ 6,212,459	$ 6,122,000	$ 6,024,000	$ 5,886,000	
10 Line 4	$ (316,000)	$ (292,000)	$ (243,000)	$ (122,000)	$ 0	
11 Line 18	69.7326%	69.7326%	69.7326%	69.7326%	69.7326%	
12 Line 10 * Line 11	$ (220,355)	$ (203,619)	$ (169,450)	$ (85,074)	$ 0	
13 Line 9 + Line 12	$ 5,179,117	$ 6,008,840	$ 5,952,550	$ 5,938,926	$ 5,886,000	$ 28,965,433
14 NiMo One Time FAS 106	$ 294,534					
15 Service Company One Time FAS 106	$ 678,572					
16 Total One Time FAS 106	$ 973,106					
17 NiMo Percent One Time FAS 106	30.2674%					
18 Service Company Percent One Time FAS 106	69.7326%					

September 5, 2008 Version

Calculation of Service Company OPEB

Year Ended	3/31/2008	3/31/2009	**3/31/2010**	3/31/2011
1 FAS 106 Non Union OPEB Cost Page 6	$ 13,959,477	$ 15,980,047	**$ 14,822,262**	$ 14,078,614
2 One Time FAS 106 Expense Page 5	$ (395,000)	$ (380,000)	**$ (313,000)**	$ (149,000)
3 Line 10	82.1635%	82.1635%	**82.1635%**	82.1635%
4 Line 2 * Line 3	$ (324,546)	$ (312,221)	**$ (257,172)**	$ (122,424)
5 Line 1 + Line 4	$ 13,634,931	$ 15,667,826	**$ 14,565,090**	$ 13,956,190
6 FAS 106 Union OPEB Cost Page 10	$ 1,708,472	$ 1,611,377	**$ 1,710,700**	$ 1,676,372
7 Line 5 + Line 6	$ 15,343,403	$ 17,279,203	**$ 16,275,790**	$ 15,632,562
8 Service Company One Time Benefits	$ 1,016,275			
9 Total One Time Benefits	$ 1,236,893			
10 Line 8 / Line 9	82.1635%			

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Operating Expenses by Component
Pensions - Expense Type B06

With Staff Calculations

	Filed 4/2009-3/2010	Revised 4/2009-3/2010	Variance Revised over/(under) Filed
1 Pension - New Reg Amortization	1,740,528.00	1,740,528.00	-
2 Pension Expense	4,482,260.59	5,337,908.70	855,648.11
3 Less: Amount Capitalized	(1,565,031.33)	(2,176,024.70)	(610,993.37)
4 Service Co Allocation (including NY svc co. emp.)	248,109.51	122,944.23	(125,165.29)
5 Total Gas Pension Expense	4,905,866.77	5,025,356.23	119,489.46
6 Rate Allowance	4,750,000.00	5,025,356.23	275,356.23

Notes:
1 Sheet 2 , Line 2 $10,238,400 x 17% = $1,740,528
2 17% * (Sheet 2, Line 1 - Sheet 2, Line 7)
3 30.7416% of Line 1 and Line 2 based on forecast capitalization
4 25.76% of Service Company based on forecast allocation (Sheet 3, Lines 1 and 6)*17%
5 Sum of lines 1 through 4
6 Joint Proposal Attachment 16, Sheet 5, Line 5
7 Line 5 - Line 6
8 None
9 Line 7 - Line 8

September 5, 2008 Version

Calculation of NIMO Pension Year Ended	3/31/2008	3/31/2009	**3/31/2010**	3/31/2011	3/31/2012
1 FAS 87 Pension Cost Page 36	$ 63,156,132	$ 43,214,249	**$ 44,207,000**	$ 42,884,000	$ 42,850,000
2 Regulatory Expense Page 35	$ (10,238,400)	$ (10,238,400)	**$ (10,238,400)**	$ (10,238,400)	$ (10,238,400)
3 Line 1 + Line 2	$ 52,917,732	$ 32,975,849	**$ 33,968,600**	$ 32,645,600	$ 32,611,600
4 FAS 88 Special Termination Benefits Page 35	$ (9,272,000)	$ (8,559,000)	**$ (7,132,000)**	$ (3,566,000)	
5 Line 17	36.0227%	36.0227%	**36.0227%**	36.0227%	
6 Line 4 * Line 5	$ (3,340,022)	$ (3,083,181)	**$ (2,569,137)**	$ (1,284,569)	
7 Line 3 + Line 6	$ 49,577,710	$ 29,892,668	**$ 31,399,463**	$ 31,361,031	$ 32,611,600
8 Regulatory Expense Page 35	$ 10,238,400	$ 10,238,400	**$ 10,238,400**	$ 10,238,400	$ 10,238,400
9 FAS 87 Pension Cost Page 36	$ 12,329,702	$ 10,326,056	**$ 9,669,000**	$ 7,505,000	$ 5,456,000
10 Line 4	$ (9,272,000)	$ (8,559,000)	**$ (7,132,000)**	$ (3,566,000)	$ 0
11 Line 18	63.9773%	63.9773%	**63.9773%**	63.9773%	63.9773%
12 Line 10 * Line 11	$ (5,931,978)	$ (5,475,819)	**$ (4,562,863)**	$ (2,281,431)	$ 0
13 Line 9 + Line 12	$ 6,397,724	$ 4,850,237	**$ 5,106,137**	$ 5,223,569	$ 5,456,000
14 NiMo VERO	$ 10,276,750				
15 Service Company VERO	$ 18,251,810				
16 Total VERO	$ 28,528,560				
17 NiMo Percent VERO	36.0227%				
18 Service Company Percent VERO	63.9773%				

September 5, 2008 Version

Calculation of Service Company Pension

Year Ended	3/31/2008	3/31/2009	**3/31/2010**	3/31/2011	3/31/2012
1 FAS 87 Pension Cost Page 2	$ 20,838,028	$ 17,990,816	**$ 9,926,569**	$ 2,849,284	$ (2,137,553)
2 FAS 88 Special Termination Benefits Page 1	$ (21,319,000)	$ (21,776,377)	**$ (14,535,000)**	$ (6,917,000)	
3 Line 8	84.1090%	84.1090%	**84.1090%**	84.1090%	84.1090%
4 Line 2 * Line 3	$ (17,931,204)	$ (18,315,899)	**$ (12,225,247)**	$ (5,817,822)	
5 Line 1 + Line 4	$ 2,906,824	$ (325,083)	**$ (2,298,678)**	$ (2,968,538)	$ (2,137,553)
6 Service Company VERO	$ 48,340,426				
7 Total VERO	$ 57,473,527				
8 Line 6 / Line 7	84.1090%				

Excerpts from
PSC Request 354 – Gerbsch (DAG-41) Supplemental
Second CTC Reset Compliance Filing Case 01-M-0075

Date of Request_9/7/06__ Request No. _PSC-354 Gerbsch (DAG-41)_Supplemental

NMPC Req. No. _418_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-354 Gerbsch (DAG-41)___

Request:

The Company in its reply testimony at page 100 of the Volume 1 testimony references two corrections to be made to the pension and OPEBs expense (per Hewitt valuations) used in staff 's calculation for FYE 3/06, as shown in Exhibit __ (SP-7) page 32. The Company's corrections are based on more recent reports from National Grid's actuary, Hewitt Associates. Staff previously requested, via PSC-176 and PSC-177, to be provided copies of any new updated actuary estimates provided by the actuary. The last actuary estimate to be provided for pension expense as part of the Company's response to PSC-176 was the actuarial estimate as of September 9, 2005. The last actuary estimate to be provided for OPEBs expense as part of the Company's response to PSC-177 was the actuarial estimate as of September 30, 2005.

1. Provide copies of all actuary letters/correspondence, in their entirety, that contain updated actuary estimates (including the final actual) provided by the actuary to the Company subsequent to the September 9, 2005 estimate as it pertains to pension expense for both Niagara Mohawk and National Grid USA, for FYE 3/06 as well as for future fiscal year periods.

2. Provide copies of all actuary letters/correspondence, in their entirety, that contain updated actuary estimates (including the final actual) provided by the actuary to the Company subsequent to the September 30, 2005 estimate as it pertains to OPEBs expense for both Niagara Mohawk and National Grid USA, for FYE 3/06 as well as for future fiscal year periods.

3. The information requested in questions 1-2 above should be provided on an ongoing basis, for any new updated actuarial estimates/final actuals provided by the actuary.

Form 103

Supplemental Response:

Attached please find the following supplemental information:

(1) National Grid USA 5-Year Expense Projections, Dated September 5, 2008.

Name of Respondent: James Fletcher Date of Reply: September 12, 2008

Form 103

PSC-354 (CTC Reset Case)

Hewitt Consulting

5–Year Expense Projections

National Grid USA

September 5, 2008

Summary

- Actual FY 2009 expense results reflected for all plans except for the estimated NiMo SERP and Special Termination Benefits due to the nonunion and union VEROs
- For U.S. GAAP purposes, Special Termination Benefit charges, due to the VERO, are reflected through Fiscal Year 2011. For U.K. GAAP, these charges were reflected in Fiscal Year 2008.
- Special Termination Benefit charges due to the union FAPP VERO have been reflected
- Estimated Settlement Accounting reflected for NiMo SERP
- March 31, 2008 assets used for projecting assets
- Expected contributions are based on information provided by National Grid
- Discount rate and expected ROA assumptions provided by National Grid
- Mortality Table change for nonunion participants has been reflected for FY 2009 and beyond
- For UK accounting, projections based on IAS 19 under SORIE approach
- FAS 106 expense reflects the anticipated future Medicare Part D subsidy amounts

National Grid USA
Estimated US GAAP Expense Under FAS 87/106
Current and 5 Year Projection

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Estimated FAS 87/106 Ongoing Expense						
NG FAPP Pension	$ (2,789,126)	$ (4,797,000)	$ (7,444,000)	$ (4,767,000)	$ (766,000)	$ (830,000)
NG Retiree Welfare Nonunion	$ 30,753,729	$ 29,602,000	$ 28,005,000	$ 26,473,000	$ 24,959,000	$ 22,974,000
NG Retiree Welfare Union	$ 13,796,414	$ 13,343,000	$ 13,153,000	$ 13,343,000	$ 13,859,000	$ 13,592,000
NG Nonqualified ESRP	$ 7,546,045	$ 7,859,000	$ 7,788,000	$ 7,541,000	$ 7,450,000	$ 7,381,000
NG Nonqualified Deferred Comp. Plan	$ 1,559,212	$ 1,515,000	$ 1,457,000	$ 1,397,000	$ 1,338,000	$ 1,277,000
NG Nonqualified Exec. Life Plan	$ 980,230	$ 946,000	$ 905,000	$ 865,000	$ 826,000	$ 787,000
EUA Nonqualified Supplemental Plan	$ 39,951	$ 24,390	$ 9,000	$ 0	$ (9,000)	$ (17,000)
EUA Nonqualified KEIP Plan	$ 115,346	$ 120,000	$ 105,000	$ 89,000	$ 74,000	$ 58,000
NG and EUA Directors Plans	$ 142,329	$ 135,000	$ 127,000	$ 120,000	$ 112,000	$ 106,000
Subtotal National Grid Plans	**$ 52,144,130**	**$ 48,747,390**	**$ 44,105,000**	**$ 45,061,000**	**$ 47,843,000**	**$ 45,328,000**
NiMo Pension Plan	$ 44,981,305	$ 46,744,000	$ 46,823,000	$ 48,306,000	$ 48,246,000	$ 30,160,000
NiMo Retiree Welfare Nonunion	$ 53,100,453	$ 51,387,000	$ 50,288,000	$ 49,131,000	$ 47,911,000	$ 45,914,000
NiMo Retiree Welfare Union	$ 87,986,488	$ 84,430,000	$ 79,992,000	$ 78,045,000	$ 74,948,000	$ 74,041,000
NiMo Nonqualified SERP	$ 480,000	$ 430,000	$ 420,000	$ 404,000	$ 385,000	$ 364,000
Subtotal Niagara Mohawk Plans	**$ 186,548,246**	**$182,991,000**	**$177,523,000**	**$175,886,000**	**$171,490,000**	**$150,479,000**
Estimated One-time FAS 88/106 Expense - NE	$ 23,256,377	$ 15,762,000	$ 7,524,000	$ 0	$ 0	$ 0
Estimated One-time FAS 88/106 Expense - NY	$ 9,411,000	$ 7,375,000	$ 3,688,000	$ 0	$ 0	$ 0
Total Expense for New England	**$ 75,400,507**	**$ 64,509,390**	**$ 51,629,000**	**$ 45,061,000**	**$ 47,843,000**	**$ 45,328,000**
Total Expense for New York	**$ 195,959,246**	**$190,366,000**	**$181,211,000**	**$175,886,000**	**$171,490,000**	**$150,479,000**
Estimated FAS 87/106 Ongoing Expense						
Granite State	$ 499,273	$ 415,873	$ 346,302	$ 341,907	$ 359,936	$ 312,243
Mass Electric	$ 14,223,932	$ 13,461,986	$ 11,351,324	$ 11,686,894	$ 12,592,232	$ 11,787,251
Nantucket Electric	$ 247,515	$ 233,516	$ 229,590	$ 234,182	$ 249,130	$ 252,406
Narragansett Electric	$ 6,018,289	$ 5,121,559	$ 4,423,997	$ 4,544,293	$ 4,928,060	$ 4,502,963
NE Gas	$ 11,844,433	$ 12,418,870	$ 11,478,310	$ 11,024,102	$ 11,551,166	$ 11,754,132
New England Power	$ (3,624,856)	$ (4,202,136)	$ (4,749,214)	$ (4,861,603)	$ (4,842,368)	$ (5,256,528)
NGUSCO	$ 45,941,373	$ 36,819,573	$ 28,320,565	$ 21,874,264	$ 22,799,978	$ 21,780,901
Directors	$ 250,547	$ 240,149	$ 228,124	$ 216,959	$ 204,864	$ 194,631
Subtotal National Grid Plans	**$ 75,400,506**	**$ 64,509,390**	**$ 51,628,998**	**$ 45,060,998**	**$ 47,842,998**	**$ 45,327,999**
Niagara Mohawk	$ 179,420,731	$174,575,000	$167,682,000	$164,544,000	$160,047,000	$140,396,000
NGUSCO	$ 16,538,515	$ 15,791,000	$ 13,529,000	$ 11,342,000	$ 11,443,000	$ 10,083,000
Subtotal Niagara Mohawk Plans	**$ 195,959,246**	**$190,366,000**	**$181,211,000**	**$175,886,000**	**$171,490,000**	**$150,479,000**
Total Expense	**$ 271,359,752**	**$254,875,390**	**$232,839,998**	**$220,946,998**	**$219,332,998**	**$195,806,999**

Hewitt Associates

National Grid USA
Estimated US GAAP Expense Under FAS 87/106
Current and 5 Year Projection

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets						
Pension Plans	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Retiree Welfare Nonunion - NE	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Retiree Welfare Nonunion - Nimo	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Retiree Welfare Union - NE	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Retiree Welfare Union - Nimo	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
Actual Return on Assets for Projection						
Pension Plans	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Retiree Welfare Nonunion	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Retiree Welfare Union - NE	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Retiree Welfare Union - Nimo	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
Initial Trend						
Pre-65 Medical	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Post-65 Medical	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table						
Union Participants	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH
Nonunion Participants	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15
Expected Contribution						
NG FAPP Pension (boy)	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 0	$ 0	$ 0
NG Retiree Welfare Nonunion (boy)	$ 24,000,000	$ 42,000,000	$ 42,000,000	$ 42,000,000	$ 42,000,000	$ 42,000,000
NG Retiree Welfare Union (boy)	$ 13,000,000	$ 11,800,000	$ 11,600,000	$ 11,800,000	$ 12,300,000	$ 12,000,000
NiMo Pension Plan	$ 143,700,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000
NiMo Retiree Welfare Nonunion	$ 38,000,000	$ 45,000,000	$ 45,000,000	$ 45,000,000	$ 45,000,000	$ 45,000,000
NiMo Retiree Welfare Union	$ 72,950,000	$105,000,000	$ 58,000,000	$ 78,000,000	$ 60,000,000	$ 60,000,000

Hewitt Associates

National Grid USA
Final Average Pay Pension Plan
Estimated FAS 87 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Reconciliation of Funded Status, 4/1						
Projected Benefit Obligation	$ (1,496,101,287)	$ (1,537,978,000)	$ (1,576,379,000)	$ (1,610,744,000)	$ (1,641,554,000)	$ (1,675,541,000)
Fair Value of Assets	1,459,328,411	1,526,075,000	1,598,161,000	1,676,014,000	1,706,095,000	1,738,583,000
Funded Status	$ (36,772,876)	$ (11,903,000)	$ 21,782,000	$ 65,270,000	$ 64,541,000	$ 63,042,000
Unrecognized:						
• Net Transition Obligation or (Asset)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	11,256,921	9,524,000	7,791,000	6,058,000	4,325,000	2,592,000
• Net (Gain) or Loss	418,252,978	407,637,000	397,456,000	387,737,000	376,475,000	361,982,000
(Accrued) / Prepaid Pension Cost	$ 392,737,023	$ 405,258,000	$ 427,029,000	$ 459,065,000	$ 445,341,000	$ 427,616,000
Net Periodic Pension Cost						
Service Cost	$ 26,103,303	$ 27,147,000	$ 28,233,000	$ 29,362,000	$ 30,536,000	$ 31,757,000
Interest Cost	93,996,582	96,719,000	99,215,000	101,448,000	103,451,000	105,660,000
Expected Return on Assets	(121,820,417)	(126,617,000)	(131,962,000)	(132,785,000)	(133,084,000)	(135,459,000)
Amortization of:						
• Net Transition Obligation or (Asset)	0	0	0	0	0	0
• Prior Service Cost	1,733,405	1,733,000	1,733,000	1,733,000	1,733,000	1,733,000
• Net (Gain) or Loss	15,689,440	14,712,000	13,828,000	13,966,000	15,089,000	13,970,000
FAS 87 Pension Expense/(Income)	**$ 15,702,313**	**$ 13,694,000**	**$ 11,047,000**	**$ 13,724,000**	**$ 17,725,000**	**$ 17,661,000**
FAS 88 Special Termination Benefits	$ 21,776,377	$ 14,535,000	$ 6,917,000	$ 0	$ 0	$ 0
FAS 88 Curtailment Expense	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Regulatory Expense/(Income)	$ (18,491,439)	$ (18,491,000)	$ (18,491,000)	$ (18,491,000)	$ (18,491,000)	$ (18,491,000)
Total Pension Expense/(Income)	**$ 18,987,251**	**$ 9,738,000**	**$ (527,000)**	**$ (4,767,000)**	**$ (766,000)**	**$ (830,000)**
Expected Benefit Payments	$ 100,000,000	$ 100,000,000	$ 100,000,000	$ 100,000,000	$ 100,000,000	$ 100,000,000
Expected Contributions	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 0	$ 0	$ 0
Market Related Value of Assets	$ 1,522,755,204	$ 1,582,712,000	$ 1,649,522,000	$ 1,709,815,000	$ 1,713,551,000	$ 1,743,232,000
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Salary Scale						
Nonunion	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Union	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Mortality Table for Union	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH
Mortality Table for Nonunion	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

National Grid USA
Final Average Pay Pension Plan
Estimated FAS 87 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Net Periodic Pension Cost						
National Grid Plans						
Granite State	$ (120,148)	$ (170,649)	$ (203,334)	$ (176,779)	$ (135,003)	$ (139,671)
Mass Electric	$ (562,789)	$ (1,451,663)	$ (2,949,538)	$ (2,203,999)	$ (1,060,743)	$ (1,121,978)
Nantucket Electric	$ 87,770	$ 69,122	$ 64,334	$ 74,010	$ 87,499	$ 89,882
Narragansett Electric	$ (1,951,772)	$ (2,308,928)	$ (2,712,296)	$ (2,387,326)	$ (1,875,266)	$ (1,934,329)
NE Gas	$ 6,673,725	$ 7,025,984	$ 6,076,648	$ 5,602,262	$ 6,076,803	$ 6,280,426
NE Power	$ (3,130,352)	$ (3,352,436)	$ (3,652,097)	$ (3,537,615)	$ (3,318,902)	$ (3,430,050)
NGUSCO	$ 17,990,816	$ 9,926,569	$ 2,849,284	$ (2,137,553)	$ (540,389)	$ (574,280)
Directors	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Total Expense/(Income)	**$ 18,987,251**	**$ 9,738,000**	**$ (527,000)**	**$ (4,767,000)**	**$ (766,000)**	**$ (830,000)**
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Salary Scale						
Nonunion	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Union	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Mortality Table for Union	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH
Mortality Table for Nonunion	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

[Page 2]

National Grid USA
Nonunion Retiree Welfare Plan
Estimated FAS 106 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Reconciliation of Funded Status, 4/1						
Accumulated Postret. Ben. Obligation	$ (432,503,295)	$ (440,422,000)	$ (447,879,000)	$ (454,800,000)	$ (461,386,000)	$ (467,881,000)
Fair Value of Assets	185,743,559	197,729,000	228,516,000	260,141,000	292,867,000	326,768,000
Funded Status	$ (246,759,736)	$ (242,693,000)	$ (219,363,000)	$ (194,659,000)	$ (168,519,000)	$ (141,113,000)
Unrecognized:						
• Net Transition Obligation or (Asset)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	(5,106,512)	(4,358,000)	(3,610,000)	(2,862,000)	(2,114,000)	(1,366,000)
• Net (Gain) or Loss	157,927,236	151,406,000	144,797,000	138,470,000	132,288,000	126,154,000
(Accrued) / Prepaid Cost	$ (93,939,012)	$ (95,645,000)	$ (78,176,000)	$ (59,051,000)	$ (38,345,000)	$ (16,325,000)
Net Periodic Cost						
Service Cost	$ 5,462,626	$ 5,729,000	$ 6,008,000	$ 6,301,000	$ 6,608,000	$ 6,930,000
Interest Cost	27,337,229	27,815,000	28,264,000	28,685,000	29,087,000	29,476,000
Expected Return on Assets	(14,048,593)	(15,859,000)	(17,776,000)	(19,701,000)	(21,660,000)	(23,890,000)
Amortization of:						
• Net Transition Obligation or (Asset)	0	0	0	0	0	0
• Prior Service Cost	(748,153)	(748,000)	(748,000)	(748,000)	(748,000)	(748,000)
• Net (Gain) or Loss	7,265,636	7,181,000	6,778,000	6,457,000	6,193,000	5,727,000
FAS 106 Expense	**$ 25,268,745**	**$ 24,118,000**	**$ 22,526,000**	**$ 20,994,000**	**$ 19,480,000**	**$ 17,495,000**
FAS 106 Special Termination Benefits	$ 380,000	$ 313,000	$ 149,000	$ 0	$ 0	$ 0
FAS 106 Curtailment Expense	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Regulatory Expense	$ 5,484,984	$ 5,484,000	$ 5,479,000	$ 5,479,000	$ 5,479,000	$ 5,479,000
Total RW Expense	**$ 31,133,729**	**$ 29,915,000**	**$ 28,154,000**	**$ 26,473,000**	**$ 24,959,000**	**$ 22,974,000**
Expected Benefit Payments - Net	$ 23,861,000	$ 25,000,000	$ 26,100,000	$ 27,000,000	$ 27,800,000	$ 28,800,000
Expected Benefit Payments - Gross	$ 25,318,000	$ 26,500,000	$ 27,700,000	$ 28,700,000	$ 29,700,000	$ 30,700,000
Expected Contributions	$ 24,000,000	$ 42,000,000	$ 42,000,000	$ 42,000,000	$ 42,000,000	$ 42,000,000
Market Related Value of Assets	$ 196,786,345	$ 206,205,000	$ 235,196,000	$ 264,224,000	$ 293,735,000	$ 327,275,000
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

National Grid USA
Nonunion Retiree Welfare Plan
Estimated FAS 106 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Net Periodic Cost						
National Grid Plans						
Granite State	$ 386,967	$ 359,456	$ 327,562	$ 296,506	$ 265,568	$ 226,801
Mass Electric	$ 7,952,774	$ 8,000,436	$ 7,484,759	$ 6,997,091	$ 6,512,292	$ 5,900,203
Nantucket Electric	$ 75,657	$ 71,546	$ 72,191	$ 72,947	$ 73,790	$ 74,385
Narragansett Electric	$ 4,177,749	$ 3,854,668	$ 3,602,251	$ 3,357,162	$ 3,113,504	$ 2,805,628
NE Gas	$ 3,441,075	$ 3,626,026	$ 3,607,942	$ 3,590,449	$ 3,593,998	$ 3,573,286
NE Power	$ (880,540)	$ (819,394)	$ (1,019,319)	$ (1,216,398)	$ (1,414,428)	$ (1,653,980)
NGUSCO	$ 15,980,047	$ 14,822,262	$ 14,078,614	$ 13,375,244	$ 12,814,275	$ 12,047,678
Directors	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Total Expense/(Income)	**$ 31,133,729**	**$ 29,915,000**	**$ 28,154,000**	**$ 26,473,000**	**$ 24,959,000**	**$ 22,974,000**
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

National Grid USA
Union Retiree Welfare Plan
Estimated FAS 106 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Reconciliation of Funded Status, 4/1						
Accumulated Postret. Ben. Obligation	$ (391,318,779)	$ (399,886,000)	$ (407,864,000)	$ (415,577,000)	$ (423,123,000)	$ (430,607,000)
Fair Value of Assets	252,890,633	264,201,000	273,885,000	283,006,000	292,055,000	301,351,000
Funded Status	$ (138,428,146)	$ (135,685,000)	$ (133,979,000)	$ (132,571,000)	$ (131,068,000)	$ (129,256,000)
Unrecognized:						
• Net Transition Obligation or (Asset)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	(4,957,968)	(4,483,000)	(4,008,000)	(3,533,000)	(3,058,000)	(2,583,000)
• Net (Gain) or Loss	133,454,417	129,369,000	125,704,000	122,227,000	118,565,000	114,378,000
(Accrued) / Prepaid Cost	$ (9,931,697)	$ (10,799,000)	$ (12,283,000)	$ (13,877,000)	$ (15,561,000)	$ (17,461,000)
Net Periodic Cost						
Service Cost	$ 4,875,228	$ 5,113,000	$ 5,362,000	$ 5,623,000	$ 5,897,000	$ 6,184,000
Interest Cost	24,751,303	25,265,000	25,751,000	26,223,000	26,687,000	27,138,000
Expected Return on Assets	(22,210,368)	(23,104,000)	(23,726,000)	(24,195,000)	(24,507,000)	(25,204,000)
Amortization of:						
• Net Transition Obligation or (Asset)	0	0	0	0	0	0
• Prior Service Cost	(475,320)	(475,000)	(475,000)	(475,000)	(475,000)	(475,000)
• Net (Gain) or Loss	5,295,394	4,985,000	4,682,000	4,608,000	4,698,000	4,390,000
FAS 106 Expense	**$ 12,236,237**	**$ 11,784,000**	**$ 11,594,000**	**$ 11,784,000**	**$ 12,300,000**	**$ 12,033,000**
FAS 106 Special Termination Benefits	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
FAS 106 Curtailment Expense	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Regulatory Expense	$ 1,560,177	$ 1,559,000	$ 1,559,000	$ 1,559,000	$ 1,559,000	$ 1,559,000
Total RW Expense	**$ 13,796,414**	**$ 13,343,000**	**$ 13,153,000**	**$ 13,343,000**	**$ 13,859,000**	**$ 13,592,000**
Expected Benefit Payments - Net	$ 21,059,000	$ 22,400,000	$ 23,400,000	$ 24,300,000	$ 25,100,000	$ 26,200,000
Expected Benefit Payments - Gross	$ 22,690,000	$ 23,900,000	$ 25,000,000	$ 26,000,000	$ 27,000,000	$ 28,100,000
Expected Contributions	$ 13,000,000	$ 11,800,000	$ 11,600,000	$ 11,800,000	$ 12,300,000	$ 12,000,000
Market Related Value of Assets	$ 267,561,582	$ 278,504,000	$ 288,287,000	$ 294,273,000	$ 297,551,000	$ 306,553,000
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH

Hewitt Associates

National Grid USA
Union Retiree Welfare Plan
Estimated FAS 106 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Net Periodic Cost						
National Grid Plans						
Granite State	$ 196,113	$ 190,640	$ 188,267	$ 191,577	$ 199,761	$ 196,484
Mass Electric	$ 6,613,220	$ 6,693,301	$ 6,600,527	$ 6,694,401	$ 6,946,947	$ 6,820,626
Nantucket Electric	$ 42,373	$ 49,393	$ 50,220	$ 51,330	$ 52,653	$ 53,540
Narragansett Electric	$ 3,648,695	$ 3,430,511	$ 3,390,940	$ 3,437,214	$ 3,555,935	$ 3,500,764
NE Gas	$ 1,729,633	$ 1,766,860	$ 1,793,720	$ 1,831,392	$ 1,880,364	$ 1,900,421
NE Power	$ (44,997)	$ (498,406)	$ (547,047)	$ (566,842)	$ (561,472)	$ (619,510)
NGUSCO	$ 1,611,377	$ 1,710,700	$ 1,676,372	$ 1,703,929	$ 1,784,810	$ 1,739,676
Directors	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Total Expense/(Income)	**$ 13,796,414**	**$ 13,343,000**	**$ 13,153,000**	**$ 13,343,000**	**$ 13,859,000**	**$ 13,592,000**
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH

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National Grid USA
Niagara Mohawk Pension Plan
Estimated FAS 87 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Reconciliation of Funded Status, 4/1						
Projected Benefit Obligation	$(1,188,923,888)	$(1,223,962,000)	$(1,236,189,000)	$(1,238,787,000)	$(1,231,200,000)	$(1,216,404,000)
Fair Value of Assets	1,159,404,074	1,297,125,000	1,348,728,000	1,396,140,000	1,439,025,000	1,477,020,000
Funded Status	$ (29,519,814)	$ 73,163,000	$ 112,539,000	$ 157,353,000	$ 207,825,000	$ 260,616,000
Unrecognized:						
• Net Transition Obligation or (Asset)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	36,782,086	32,770,000	28,758,000	24,746,000	20,734,000	16,722,000
• Net (Gain) or Loss	214,213,340	216,027,000	187,111,000	156,244,000	121,802,000	85,101,000
(Accrued) / Prepaid Pension Cost	$ 221,475,612	$ 321,960,000	$ 328,408,000	$ 338,343,000	$ 350,361,000	$ 362,439,000
Net Periodic Pension Cost						
Service Cost	$ 27,448,626	$ 28,787,000	$ 30,190,000	$ 31,662,000	$ 33,206,000	$ 34,825,000
Interest Cost	74,030,053	76,308,000	76,842,000	76,751,000	75,998,000	74,744,000
Expected Return on Assets	(100,177,440)	(106,032,000)	(109,170,000)	(111,221,000)	(113,077,000)	(115,431,000)
Amortization of:						
• Net Transition Obligation or (Asset)	0	0	0	0	0	0
• Prior Service Cost	4,012,289	4,012,000	4,012,000	4,012,000	4,012,000	4,012,000
• Net (Gain) or Loss	29,343,361	33,345,000	34,625,000	36,778,000	37,783,000	21,686,000
FAS 87 Pension Expense	**$ 34,656,889**	**$ 36,420,000**	**$ 36,499,000**	**$ 37,982,000**	**$ 37,922,000**	**$ 19,836,000**
FAS 88 Settlement Expense	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
FAS 88 Special Termination Benefits	$ 8,559,000	$ 7,132,000	$ 3,566,000	$ 0	$ 0	$ 0
Regulatory Expense	$ 10,324,416	$ 10,324,000	$ 10,324,000	$ 10,324,000	$ 10,324,000	$ 10,324,000
Total Pension Expense	**$ 53,540,305**	**$ 53,876,000**	**$ 50,389,000**	**$ 48,306,000**	**$ 48,246,000**	**$ 30,160,000**
Expected Benefit Payments	$ 100,000,000	$ 100,000,000	$ 108,000,000	$ 116,000,000	$ 124,000,000	$ 133,000,000
Expected Contributions	$ 143,700,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000
Market Related Value of Assets	$ 1,223,621,200	$ 1,352,478,000	$ 1,395,712,000	$ 1,425,352,000	$ 1,452,552,000	$ 1,486,476,000
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Salary Scale	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%
Mortality Table for Union	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH
Mortality Table for Nonunion	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

National Grid USA
Niagara Mohawk Pension Plan
Estimated FAS 87 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Net Periodic Pension Cost						
Niagara Mohawk Pension Plan						
Niagara Mohawk	$ 43,214,249	$ 44,207,000	$ 42,884,000	$ 42,850,000	$ 42,671,000	$ 25,853,000
NGUSCO	$ 10,326,056	$ 9,669,000	$ 7,505,000	$ 5,456,000	$ 5,575,000	$ 4,307,000
Total FAS 87/88 Expense	**$ 53,540,305**	**$ 53,876,000**	**$ 50,389,000**	**$ 48,306,000**	**$ 48,246,000**	**$ 30,160,000**
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Salary Scale	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%
Mortality Table for Union	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH
Mortality Table for Nonunion	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

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Niagara Mohawk
Nonunion Retiree Welfare Plan
Estimated FAS 106 Expense

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	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Reconciliation of Funded Status, 4/1						
Accumulated Postret. Ben. Obligation	$ (451,945,005)	$ (459,520,000)	$ (466,596,000)	$ (473,229,000)	$ (479,505,000)	$ (485,639,000)
Fair Value of Assets	106,175,610	125,883,000	152,802,000	180,298,000	208,616,000	237,812,000
Funded Status	$ (345,769,395)	$ (333,637,000)	$ (313,794,000)	$ (292,931,000)	$ (270,889,000)	$ (247,827,000)
Unrecognized:						
• Net Transition Obligation or (Asset)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	(2,019,005)	(1,753,000)	(1,487,000)	(1,221,000)	(955,000)	(689,000)
• Net (Gain) or Loss	90,336,424	75,703,000	62,108,000	48,513,000	34,918,000	21,323,000
(Accrued) / Prepaid Cost	$ (257,451,976)	$ (259,687,000)	$ (253,173,000)	$ (245,639,000)	$ (236,926,000)	$ (227,193,000)
Net Periodic Cost						
Service Cost	$ 4,909,014	$ 5,148,000	$ 5,399,000	$ 5,662,000	$ 5,938,000	$ 6,227,000
Interest Cost	28,610,855	29,066,000	29,493,000	29,895,000	30,277,000	30,644,000
Expected Return on Assets	(7,174,821)	(8,119,000)	(9,896,000)	(11,718,000)	(13,596,000)	(15,533,000)
Amortization of:						
• Net Transition Obligation or (Asset)	0	0	0	0	0	0
• Prior Service Cost	(265,660)	(266,000)	(266,000)	(266,000)	(266,000)	(266,000)
• Net (Gain) or Loss	15,058,269	13,595,000	13,595,000	13,595,000	13,595,000	12,879,000
FAS 106 Expense	**$ 41,137,657**	**$ 39,424,000**	**$ 38,325,000**	**$ 37,168,000**	**$ 35,948,000**	**$ 33,951,000**
One-time FAS 106 Expense	$ 292,000	$ 243,000	$ 122,000	$ 0	$ 0	$ 0
Regulatory Expense	$ 11,962,796	$ 11,963,000	$ 11,963,000	$ 11,963,000	$ 11,963,000	$ 11,963,000
Total RW Expense	**$ 53,392,453**	**$ 51,630,000**	**$ 50,410,000**	**$ 49,131,000**	**$ 47,911,000**	**$ 45,914,000**
Expected Benefit Payments - Net	$ 23,556,000	$ 24,700,000	$ 25,700,000	$ 26,600,000	$ 27,400,000	$ 28,400,000
Expected Benefit Payments - Gross	$ 25,042,000	$ 26,200,000	$ 27,400,000	$ 28,400,000	$ 29,400,000	$ 30,400,000
Expected Contributions	$ 38,000,000	$ 45,000,000	$ 45,000,000	$ 45,000,000	$ 45,000,000	$ 45,000,000
Market Related Value of Assets	$ 106,175,610	$ 125,883,000	$ 152,802,000	$ 180,298,000	$ 208,616,000	$ 237,812,000
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

Niagara Mohawk
Nonunion Retiree Welfare Plan
Estimated FAS 106 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Net Periodic Cost						
Niagara Mohawk	$ 47,179,994	$ 45,508,000	$ 44,386,000	$ 43,245,000	$ 42,043,000	$ 40,138,000
NGUSCO	$ 6,212,459	$ 6,122,000	$ 6,024,000	$ 5,886,000	$ 5,868,000	$ 5,776,000
Total FAS 106 Expense	**$ 53,392,453**	**$ 51,630,000**	**$ 50,410,000**	**$ 49,131,000**	**$ 47,911,000**	**$ 45,914,000**
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15

Hewitt Associates

Niagara Mohawk
Union Retiree Welfare Plan
Estimated FAS 106 Expense

9/5/2008

	Actual 4/2008-3/2009	Estimated 4/2009-3/2010	Estimated 4/2010-3/2011	Estimated 4/2011-3/2012	Estimated 4/2012-3/2013	Estimated 4/2013-3/2014
Reconciliation of Funded Status, 4/1						
Accumulated Postret. Ben. Obligation	$ (879,032,904)	$ (901,845,000)	$ (923,851,000)	$ (945,239,000)	$ (966,722,000)	$ (988,133,000)
Fair Value of Assets	440,481,110	498,483,000	590,599,000	639,235,000	709,613,000	764,616,000
Funded Status	$ (438,551,794)	$ (403,362,000)	$ (333,252,000)	$ (306,004,000)	$ (257,109,000)	$ (223,517,000)
Unrecognized:						
• Net Transition Obligation or (Asset)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	105,367,563	90,534,000	75,700,000	60,866,000	46,032,000	31,198,000
• Net (Gain) or Loss	96,183,516	79,661,000	63,890,000	48,119,000	32,348,000	16,577,000
(Accrued) / Prepaid Cost	$ (237,000,715)	$ (233,167,000)	$ (193,662,000)	$ (197,019,000)	$ (178,729,000)	$ (175,742,000)
Net Periodic Cost						
Service Cost	$ 12,442,611	$ 13,049,000	$ 13,685,000	$ 14,352,000	$ 15,052,000	$ 15,786,000
Interest Cost	55,665,019	57,057,000	58,403,000	59,731,000	61,059,000	62,366,000
Expected Return on Assets	(33,991,529)	(38,016,000)	(44,436,000)	(48,378,000)	(53,503,000)	(57,665,000)
Amortization of:						
• Net Transition Obligation or (Asset)	0	0	0	0	0	0
• Prior Service Cost	14,833,536	14,834,000	14,834,000	14,834,000	14,834,000	14,834,000
• Net (Gain) or Loss	17,301,631	15,771,000	15,771,000	15,771,000	15,771,000	16,985,000
FAS 106 Expense	**$ 66,251,268**	**$ 62,695,000**	**$ 58,257,000**	**$ 56,310,000**	**$ 53,213,000**	**$ 52,306,000**
One-time FAS 106 Expense	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Regulatory Expense	$ 21,735,220	$ 21,735,000	$ 21,735,000	$ 21,735,000	$ 21,735,000	$ 21,735,000
Total RW Expense	**$ 87,986,488**	**$ 84,430,000**	**$ 79,992,000**	**$ 78,045,000**	**$ 74,948,000**	**$ 74,041,000**
Expected Benefit Payments - Net	$ 45,296,000	$ 48,100,000	$ 50,700,000	$ 52,600,000	$ 54,700,000	$ 57,300,000
Expected Benefit Payments - Gross	$ 48,161,000	$ 50,900,000	$ 53,800,000	$ 56,000,000	$ 58,500,000	$ 61,100,000
Expected Contributions	$ 72,950,000	$ 105,000,000	$ 58,000,000	$ 78,000,000	$ 60,000,000	$ 60,000,000
Market Related Value of Assets	$ 440,481,110	$ 498,483,000	$ 590,599,000	$ 639,235,000	$ 709,613,000	$ 764,616,000
Assumptions:						
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Expected Return on Assets	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
Initial Trend - Pre-65	9.00%	8.25%	7.50%	6.75%	6.00%	5.25%
Initial Trend - Post-65	10.00%	9.25%	8.50%	7.75%	7.00%	6.25%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH	RP2000CH

Hewitt Associates

PSC Request RAV-8
This Gas Case 08-G-0609

Date of Request 5/30/08

Request No. RAV-8
NMPC Req. No. NM 8 DPS-8 RAV-8

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid
Case 08-G-0609 Gas Rate Case
Request for Information

FROM: Robert Visalli

Request:

A 5/14/07 settlement between the Company and the DPS called for stockholders to bear the costs of 4 consumer advocates and their related overheads. Regarding this settlement, please provide the following information:

A. Indicate when each of the 4 consumer advocates was hired, along with their salaries.
B. During 2007 and 2008 to date, show how the pension and OPEB deferrals reflect elimination of the pension and OPEB costs associated with these 4 consumer advocates. If adjustments are required, please provide the amounts with supporting workpapers, calculations and explanation as to how the amounts were derived.
C. Same as B. for the pension and OPEB internal reserve calculations.
D. For the rate year, show how the 4 consumer advocates salaries, all their overheads (i.e., not just pension and OPEBs) and their payroll taxes were removed for revenue requirement purposes. If adjustments are required, please provide the amounts with supporting workpapers, calculations and explanation as to how the amounts were derived.

Response:

A. The hire dates and salaries for the 4 consumer advocates are:

Name	Hire Date	Salary
Consumer Advocate 1	08/15/2007	$62,000
Consumer Advocate 2	09/04/2007	$68,000
Consumer Advocate 3	09/04/2007	$60,000
Consumer Advocate 4	09/04/2007	$60,000

In addition, Consumer Advocate 3 charges electric only.

B. The pension and OPEB deferrals from September 2007 to May 2008, did not reflect the elimination of the pension and OPEB costs associated with these 4 consumer advocates. This adjustment was missed and will be corrected in June's deferral calculations. Attached are the workpapers calculating the adjustment (pension costs are 4% of their annual salaries escalated annually by 3%, OPEB per a Hewitt forecast). The pension adjustment to date is

$7,500 (gas's allocation - $1,275) . The OPEB forecast from Hewitt is not currently available. The impact is believed to be of a similar magnitude as the pension impact. The Company will provide the OPEB impact as soon as possible. The Company anticipates receiving this forecast in the next few days and hopefully no later than June 13.

C. The pension and OPEB internal reserves from September 2007 to May 2008, did not reflect the elimination of the pension and OPEB costs associated with these 4 consumer advocates. This adjustment was missed and will be corrected once the issues surrounding the internal reserve audit are finalized. The adjustment (calculation provided in B. above) would also be used in the internal reserve calculations.

D. The 4 consumer advocates positions were not included in the calculations of payroll and payroll taxes for the rate year. Headcount data for the rate year was taken as of June 30, 2007. This is stated in the Testimony of the Expense Panel and Exhibit EP-1, Schedule 29. Since the 4 positions were not included in the forecast, their corresponding payroll taxes and fringes (except pension and OPEB) were also not included. The forecast for pension and OPEB expense is based on a March 2008 forecast by our actuary, Hewitt & Associates. The pension and OPEB costs for these 4 consumer advocates were included in this forecast. However, since actual pension and OPEB costs are deferred, an adjustment to the forecasted pension and OPEB regulatory asset balance and the corresponding amortization is required for this small reduction up to March 31 ,2009. Pension and OPEB expense during the rate year wouldn't change because the forecasted level of expense exceeds the proposed thresholds. (See lines 7 on Sheet 4 of 6 of Exhibit EP-1, Schedules 17 and 22, for quantification of excess). Due to the fact that the forecast will change as time goes on, this excess was not rolled into the deferrals.

Name of Respondent:	Date of Reply:
Timothy Lillis	6/09/08

RAV-8
Question D

Pension Costs for 4 Consumer Advocates

		Annual Salary at Start Date	4%	Adjustment 100%	Gas 17%		
Consumer Advocate 1	08/15/2007	$62,000					
Consumer Advocate 2	09/04/2007	$68,000					
Consumer Advocate 3	09/04/2007	$60,000					
Consumer Advocate 4	09/04/2007	$60,000					
Total		$250,000	$10,000.00	$3,333.33	$566.67	2007 4 months	
			$10,000.00	$5,000.00	$850.00	2008 6 months	1/1/08 - 6/30/08
		Salry change July	x 1.03				
			$10,300.00	$5,150.00	$875.50	2008 6 months	7/1/08-12/31/08
				$2,575.00	$437.75	2009 3 months	1/1/09-3/31/09
		Prior to Rate Year		$8,333.33	$1,416.67		
		Rate year					
			$10,300.00	$2.575.00	$437.75	3 months	4/1/09-6/30/09
			x 1.03				
			$10,609.00	$7,956.75	$1,352.65	9 months	7/1/09-3/31/10
				$10,531.75	$1,790.40		

Niagara Mohawk
Nonunion Retiree Welfare Plan
Estimated FAS 106 Expense for 4 New Hires

06/09/2008

		2008		2009		2010		2011
Reconciliation of Funded Status, 1/1								
Accumulated Postret. Ben. Obligation	$	(3,500)	$	(9,900)	$	(17,500)	$	(26,300)
Fair Value of Assets		0		0		0		0
Funded Status	$	(3,500)	$	(9,900)	$	(17,500)	$	(26,300)
Unrecognized:								
• Net Transition Obligation or (Asset)	$	0	$	0	$	0	$	0
• Prior Service Cost		0		0		0		0
• Net (Gain) or Loss		0		0		0		0
(Accrued) / Prepaid Cost	$	(3,500)	$	(9,900)	$	(17,500)	$	(26,300)
Net Periodic Cost								
Service Cost	$	6,200	$	7,000	$	7,700	$	8,400
Interest Cost		230		640		1,140		1,710
Expected Return on Assets		0		0		0		0
Amortization of:								
• Net Transition Obligation or (Asset)		0		0		0		0
• Prior Service Cost		0		0		0		0
• Net (Gain) or Loss		0		0		0		0
FAS 106 Expense	**$**	**6,430**	**$**	**7,640**	**$**	**8,840**	**$**	**10,110**

		Total	Gas
September 2007 -December 2007	**$**	**2,143**	
January 2008 - May 2008	**$**	**2,679**	
	$	4,822	820

		2008		2009		2010		2011
Expected Benefit Payments	$	0	$	0	$	0	$	0
Expected Contributions	$	0	$	0	$	0	$	0

Assumptions:	2008	2009	2010	2011
Discount Rate	6.50%	6.50%	6.50%	6.50%
Initial Trend - Post 65	10.00%	9.25%	8.50%	7.75%
Initial Trend - Pre 65	9.00%	8.25%	7.50%	6.75%
Ultimate Trend	5.00%	5.00%	5.00%	5.00%
Mortality Table	RP2000CH_15	RP2000CH_15	RP2000CH_15	RP2000CH_15
# of new hires	4	0	0	0
Average Age	39.5	40.5	41.5	42.5
Average Pay	62,500	64,550	67,100	69,800

Hewitt Associates

Excerpts from March 22, 2007 Settlement Stipulation Attachments 4, 5 and the April 17, 2007 Errata

ATTACHMENT 4

Capitalization of Pension and OPEB Costs

For both the electric and gas departments, the percentage of pension and OPEB costs to be capitalized shall be determined as follows:

1. The Company shall calculate a capitalization rate at the beginning of each fiscal year using the actuarial estimates of pension and OPEB expenses for the year, along with all other fringe benefit costs subject to capitalization, and will adjust this rate for updated actuarial and other estimates provided in September of each year. The rate may also be adjusted at other times throughout the year if there is a fluctuation in the rate of greater than +/- 20 percent.

2. After the close of each fiscal year, the Company shall compare the amount of fringe benefits (including pension and OPEB costs), payroll taxes and workers compensation actually capitalized on the books, to the amount capitalized resulting from the methodology established in its response to Information Request PSC-276 in Case No. 01-M-0075. Based on the results of this annual reconciliation, the Company will adjust the amount capitalized associated with fringe benefits (which includes, but is not limited to pension and OPEBs). In addition, the Company will adjust the applicable pension and OPEB deferral accounts to reflect the capitalized pension and OPEB costs determined pursuant to the methodology set forth in the same Information Request response.

3. Attachment 1, page 2 to this Stipulation reflects adjustments to pension and OPEB deferred costs for correcting the capitalization rate through March 31, 2006. The balances shall not be adjusted further through this date ~~for capitalization issues~~ as long as the correcting journal entries are recorded by the Company. deleted

4. Table 1 illustrates the method that will be used for the annual reconciliation described in paragraph 2, above. Table 2 includes payroll information supporting the calculation on Table 1.

<u>Journal Entry Details</u>

<u>Monthly Deferral:</u>

Pursuant to Attachment 16 of the Merger Joint Proposal, actual pension and OPEB expense comprise the following four elements:

1) Expense booked directly by the Company pursuant to FAS 87 or FAS 106, derived from actuarial reports.
2) Amortization of the regulatory asset "Unrecognized Pension Loss" or "Unrecognized OPEB Loss" created by the fair value adjustment.

3) Pension/OPEB expense allocated from the Service Company. The amount allocated from the Service Company is reduced by any SERP-related amounts as directed in Attachment 16.

Revised per 4/17/07 Errata notice

4) A reduction to pension/OPEB expense for the amount capitalized, adjusted to exclude third party billings for capital work. The amount capitalized will be determined based upon the allocation process described above, but will also be subject to adjustment annually based on a reconciliation as shown in Table 1.

Monthly, the sum of the four elements noted above are compared against a pre-established level of pension/OPEB expense contained in Attachment 16 (page 4 of 5). This pre-established level changes annually in January, and the Company takes the annual amounts contained in this schedule and divides them by twelve in order to perform a monthly reconciliation. The amount above or below the threshold is the amount deferred monthly. Separate entries are recorded for the pension and OPEB deferrals:

Pension Deferral Account:	FERC 182553, Deferred Pension Costs
OPEB Deferral Account:	FERC 182554, Deferred OPEB Costs

Pension Expense Account:	FERC 926000, Employee Pensions and Benefits, Activity AG1060
OPEB Expense Account:	FERC 926000, Employee Pensions and Benefits, Activity AG1070

Annual Reconciliation Adjustment:

An adjusting entry will be made annually, but no later than May of the subsequent fiscal year, for the reconciliation of fringe benefits capitalized to the amount to be capitalized pursuant to PSC-276 as discussed above. The entry for the reconciliation adjustment, based on the illustration included in Table 1 is as follows:

O&M Accounts	$2,400,748	
Capital Accounts		$2,400,748
Deferral Accounts	$1,707,741	
O&M Accounts		$1, 707,741

Attachment 4
Table 1

		Per Company New Method	Per Staff PSC 276	
1 Total Payroll		326,363,043		
2 3rd Party				
3 Cost of Removal				
4 Other				
5 Associated				
6 Payroll Accrual				
7 Incremental Overtime		(23,620,426)		
8 Less: Transportation Clearing Labor charged to O&M (66%)				
9 Less: Stores Clearing Labor charged to O&M (19%)				
10 Less: Non- Productive Time		(52,479,958)		
11 **NET BASE PRODUCTIVE LABOR**		250,262,659	291,203,811	
Fringe Benefits:				
12 Thrift Plan (Expense Type B07)	7,627,200	3.05%	2.62%	
13 FAS 112 (Expense Type B02)	4,456,000	1.78%	1.53%	
14 Group Insurance (Expense Type B04)	2,631,900	1.05%	0.90%	
15 Medical Care & Prescription Plans (Expense Type B03)	32,099,300	12.83%	11.02%	
16 Pension (Expense Type B06)	81,756,500	32.67%	28.08%	
17 OPEB (Expense Type B01)	117,507,147	46.95%	40.35%	
18 **TOTAL FRINGE BENEFITS**	246,078,047	**98.33%**	**84.50%**	
19 Workers Compensation (Expense Type B08)	8,064,200	3.22%	2.77%	
20 Payroll Taxes (Expense Type B09)	25,983,200	10.38%	8.92%	
21 **Total percentage to be applied to base productive Company labor for Payroll Taxes, Fringe Benefits and OPEBs:**	280,125,447	**111.93%**	**96.20%**	
22 CWIP		61,453,841		
23 Time Not Worked				
24 Cost of Removal		7,075,245		
25 3rd Party				
26 Associated Company				
27 Incremental Overtime				
28 **Capital**		68,529,086	77,244,254	
Capital percent		27.38%	26.53%	
Capitalized Amounts for:		Per Company	Per Staff	Difference
Pension		22,387,272	21,686,598	700,674
OPEBs		32,176,823	31,169,757	1,007,067
All Other Fringes		12,819,124	12,417,912	401,212
Worker's Compensation		2,208,209	2,139,097	69,112
Payroll Taxes		7,114,945	6,892,262	222,683
Total Amounts Capitalized		76,706,373	74,305,625	2,400,748

Note: For lines 1-10 above, refer to Table 2

Attachment 4
Table 2

2006 Payroll Data

	P10	P15	P20	P25	Subtotal	P21	P26	Total	TNW
CWIP	43,132,505	12,510,646	5,554,476	256,215	61,453,841	3,189,649	127,049	64,770,539	12,886,841
COR	5,764,364	333,047	950,526	27,307	7,075,245	557,536	13,654	7,646,435	1,483,675
TNW	42,062,345	8,077,555	2,339,324	734	52,479,958	-	-	52,479,958	(52,479,958)
Associated Co. Billings	2,532,727	1,277,898	65,446	8,239	3,884,310	37,781	3,476	3,925,568	814,538
3rd Party Billings	905,542	270,604	642,152	142,615	1,960,913	544,318	61,608	2,566,839	411,202
O&M	112,828,479	37,053,120	11,416,619	689,158	161,987,376	16,960,387	1,710,169	180,657,932	33,968,674
Stores Clearing	3,143,014	542,862	259,278	4,202	3,949,357	135,673	1,651	4,086,680	828,178
Transportation Clearing	6,743,024	1,043,496	485,417	1,307	8,273,243	264,195	654	8,538,091	1,734,895
Other	1,526,330	128,599	23,445	-	1,678,374	12,627	-	1,691,001	351,954
Total	218,638,330	61,237,827	21,736,682	1,129,778	302,742,616	21,702,165	1,918,261	326,363,043	(0)

CWIP	Construction Work in Progress
COR	Cost of Removal
TNW	Time Not Worked
P10	Regular Represented Labor
P15	Regular Management Labor
P20	Base OT - Represented
P25	Base OT - Management
P21	Incremental OT - Represented
P26	Incremental OT - Management

Attachment 5

Determination of Credit for Transfer of Employees to Service Company

ATTACHMENT 5

Determination of Credit for Transfer of Employees to Service Company

The annual adjustment to be made to pension and OPEB expense to account for employees who transferred to or from National Grid USA Service Company, Inc. (Service Company) throughout the year required by Section 3.8.2 of the Stipulation shall be calculated as follows:

After the close of each fiscal year, the Company shall: (1) identify all employees who transferred from Niagara Mohawk to the Service Company or from the Service Company to Niagara Mohawk during the fiscal year; and (2) making the hypothetical assumption that all employee transfers occurred on January 1 of the fiscal year, calculate the difference in pension and OPEB expense allocated between Niagara Mohawk and the Service Company for (a) the capitalized portion of pension and OPEB expense; and (b) the company's share of the monthly Service Company allocation. This adjustment for (b), above, shall be subject to Niagara Mohawk's ability to provide support to Staff that the annual pension and OPEB costs for Service Company are derived from actuarial estimates of Service Company pension and OPEB expenses for the year. The revised valuations as of January 1 will be provided by the Company's actuaries. The credit determination, if any, resulting from this Attachment 5 shall follow the determination set forth in the preceding Attachment 4.

An example calculation of the adjustment described above will be applicable from April 2006 forward and is presented in Table 1 of this Attachment.

Attachment 5
Table 1

Pension Expense

A	B	C	D	E	F	G	H	I	J	K	L
	# of Employees Transferred to Svc. Co.	Total NM Pension Expense	Pension Expense Originally Allocated to Svc. Co.	Revised Pension Expense Allocated to Svc. Co	Decrease NM Pension Expense Change	Capital %	Decrease for Amount Capitalized	Pension Adj	Svc Co Allocation % to NM	NM Share of Serv Co Allocation	Final Pension Adj
FYE 3/31/04	156	$ 50,204,699	$ 3,065,129	$ 3,363,347	(298,218)	23.95%	(71,423)	(226,795)	26.09%	(77,805)	(148,990)
FYE 3/31/05	39	$ 60,190,372	$ 4,439,886	$ 4,524,106	(84,220)	26.04%	(21,931)	(62,289)	29.20%	(24,592)	(37,697)
FYE 3/31/06	86	$ 77,659,992	$ 6,141,852	$ 6,395,794	(253,942)	26.18%	(66,482)	(187,460)	31.09%	(78,951)	(108,509)
Total Pension Adj		$ 188,055,063	$ 13,646,867	$ 14,283,247	(636,380)		(159,836)	(476,544)		(181,348)	(295,196)

OPEBs Expense

A	B	C	D	E	F	G	H	I	J	K	L
	# of Employees Transferred to Svc. Co.	Total NM OPEB Expense	OPEB Expense Originally Allocated to Svc. Co.	Revised OPEB Expense Allocated to Svc. Co	Decrease NM OPEBs Expense Change	Staff Capital %	Decrease for Amount Capitalized	OPEB Adj	Svc Co Allocation % to NM	NM Share of Serv Co Allocation	Final OPEB Adj
FYE 3/31/04	156	$ 29,370,462	$ 2,151,210	$ 2,360,509	(209,299)	23.95%	(50,127)	(159,172)	24.27%	(50,797)	(108,375)
FYE 3/31/05	39	$ 30,079,311	$ 3,646,731	$ 3,715,905	(69,174)	26.04%	(18,013)	(51,161)	28.78%	(19,908)	(31,253)
FYE 3/31/06	86	$ 33,322,910	$ 3,872,117	$ 3,944,719	(72,602)	26.18%	(19,007)	(53,595)	31.01%	(22,514)	(31,081)
Total OPEB Adj		$ 92,772,683	$ 9,670,058	$ 10,021,133	(351,075)		(87,147)	(263,928)		(93,219)	(170,709)

Column	
A	Fiscal YE
B	Number of Employees transferred to NGUSA Service Company during the fiscal year
C	Total NMPC Pension/OPEB Expense per Hewitt
D	Pension/OPEB expense originally allocated to NGUSA Service Company, excluding employees transferred during the year (based on actuarial valuations)
E	Revised pension/OPEB expense allocated to NGUSA Service Company, including employees transferred during the year (based on revised actuarial valuations)
F	Column (D) - Column (E)
G	Percentage of pension/OPEB expense capitalized (per method described in PSC-276, and as reconciled to under section 3.8.1 of the stipulation)
H	Decrease for amount capitalized (F x G)
I	Adjustment w/out service company allocation adjustment (F - H)
J	Percentage of pension/OPEB expense originally allocated from NGUSA Service Company to NM
K	Column (F) x Column (J)
L	Column (I) - Column (K)

Note: The final pension and OPEB adjustment (Column L), must be further allocated between electric and gas departments to determine the amount to be posted to electric and gas pension and OPEB deferrals.

nationalgrid

April 17, 2007

VIA HAND DELIVERY

The Honorable Jaclyn A. Brilling
Secretary, New York Public Service Commission
3 Empire State Plaza
Albany, NY 12223-1350

RE: Case No. 01-M-0075 -- Joint Petition of Niagara Mohawk Holdings, Inc., Niagara Mohawk Power Corporation, National Grid Group plc and National Grid USA for Approval of Merger and Stock Acquisition

Case No. 01-E-0011 -- Contracts Related to the Sale of Nine Mile Point Nuclear Generating Facilities From Niagara Mohawk Power Corporation, New York State Electric & Gas Corporation, Central Hudson Gas & Electric Corporation, Rochester Gas and Electric Corporation to Constellation Nuclear, LLC

Case No. 04-M-0159 -- Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems

Case No. 04-M-0938 -- Application of Niagara Mohawk Power Corporation for Authorization to Defer Actuarial Experience Pension Settlement for Fiscal Year 2004

Case No. 07-M-0173 -- Application of Niagara Mohawk Power Corporation for Authorization to Defer Actuarial Experience Pension Settlement for Fiscal Year 2007

Notice of Errata to the Stipulation of the Parties

Dear Secretary Brilling:

Enclosed for filing in the above-captioned proceedings please find the original and five copies of a Notice of Errata to the Stipulation of the Parties. This Notice of Errata is filed by Niagara Mohawk Power Corporation d/b/a National Grid on behalf of itself and the other Parties to the Stipulation.

Also enclosed are three service copies of the Notice of Errata. Please date stamp the service copies and return them to me so that we may have a copy for the other Parties and for our own files.

Respectfully submitted,

Robert Hoaglund (hmu)

Robert Hoaglund, Esq.

cc: Hon. Jeffrey E. Stockholm
Parties of record (via e-mail)

300 Erie Boulevard West, Law A-3, Syracuse, NY 13202
T: 315.428.5320 F: 315.428.5740 robert.hoaglund@us.ngrid.com www.nationalgrid.com

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Joint Petition of Niagara Mohawk Holdings, Inc., Niagara Mohawk Power Corporation, National Grid Group plc and National Grid USA for Approval of Merger and Stock Acquisition)	Case No. 01-M-0075
Contracts Related to the Sale of Nine Mile Point Nuclear Generating Facilities From Niagara Mohawk Power Corporation, New York State Electric & Gas Corporation, Central Hudson Gas & Electric Corporation, Rochester Gas and Electric Corporation to Constellation Nuclear, LLC)	Case No. 01-E-0011
Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems)	Case No. 04-M-0159
Application of Niagara Mohawk Power Corporation for Authorization to Defer Actuarial Experience Pension Settlement for Fiscal Year 2004)	Case No. 04-M-0938
Application of Niagara Mohawk Power Corporation for Authorization to Defer Actuarial Experience Pension Settlement for Fiscal Year 2007)	Case No. 07-M-0173

NOTICE OF ERRATA

On behalf of the Parties to the Stipulation of the Parties ("Stipulation") filed in the above-captioned proceedings on March 22, 2007, Niagara Mohawk Power Corporation ("Niagara Mohawk") submit this Notice of Errata to notify the Commission and the parties of the following errors in the Stipulation.

LEGAL02/30320810v2

1. A sentence was omitted from Section 3.8.3 of the Stipulation (found on page 16 of the Stipulation, which is page 23 of the March 22, 2007 filing). With the omitted sentence restored, Section 3.8.3 should read as follows:

> 3.8.3 Within ninety (90) days of a Commission Order approving this Stipulation, the Company shall submit pension and OPEB internal reserve calculations through the end of the month in which the Commission issues its Order approving this Stipulation to include adjustments agreed upon in this Stipulation, as well as other adjustments agreed to during the litigation phase of this audit. In performing the sales variance component of the Pension and OPEB deferral calculation, sales to Divested Generators would be removed, beginning April 1, 2006 and until such time that the Company actually collects revenues from the Divested Generators. The Company further agrees that the amount of pension and OPEB costs allocated to Service Company, net of pension and OPEB costs allocated back from Service Company and otherwise included in pension and OPEB cost deferrals, shall be funded on an as-incurred basis.

2. An item was omitted from the listing in Part A of Attachment 2 to the Stipulation. Accordingly, the following new item, numbered 22, should be included at the end of the list on the first page of Attachment 2 (page 49 of the March 22, 2007 filing), as follows:

> 22. Pension balance ($99,095,713) and OPEB balance ($92,109,393), each as of March 31, 2006. With respect to these deferral balances as of March 2006, no further adjustments may be made.[1]

In addition, to reflect the inclusion of item number 22 in Part A: (a) item number 5 and item number 8 should be deleted from Part B of Attachment 2 (on pages 49 and 50 of the March 22, 2007 filing); and (b) item number 3 in Attachment 4 to the Stipulation (page 62 of the March 22, 2007 filing) should be revised to delete the phrase "for capitalization issues." With that deletion, item number 3 in Attachment 4 reads as follows:

> 3. Attachment 1, page 2 to this Stipulation reflects adjustments to pension and OPEB deferred costs for correcting the capitalization rate through March 31, 2006. The balances shall not be adjusted further through this date as long as the correcting journal entries are recorded by the Company.

3. A sentence was omitted from the last paragraph on the second page of Attachment 3 to the Stipulation (page 53 of the March 22, 2007 filing). With the omitted sentence restored, that paragraph should read as follows:

> Line [C] – Employees, with listed job titles that worked the storm on that particular day, based upon their time sheets. The Directors of Divisional Operations, for the divisions not impacted by the storm, will justify the number of employees (who have listed job titles) retained in their home divisions, for each day that contractors perform storm restoration. This justification will be provided to on-site Staff, as part of the storm report. To the extent Staff disagrees with the justifications provided by the Directors of Divisional Operations for any major storm occurring after December 31, 2006, Staff may propose an adjustment to the level of actual Company employees used on Line [C] of Table 1 and 2.

4. A sentence was also omitted from the third paragraph on the third page of Attachment 3 to the Stipulation (page 54 of the March 22, 2007 filing). With the omitted sentence restored, that paragraph should read as follows:

> Line [F] – Data to be used in Lines [G] and [I]. It is the reduction of listed employees in the division (East, Central, or West) in which the major storm occurs, from the 2001 budgeted levels (remains constant during the Rate Plan Period) to levels in the month preceding a major storm. The 2001 budgeted manpower levels for the Western, Central and Eastern Divisions, respectively, are 376, 471 and 441 for Line Restoration and 54, 62, and 62 for Line Clearance.

5. The description on the second page of Attachment 4 to the Stipulation (page 63 of the March 22, 2007 filing) of the fourth element of actual pension and other

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[1] With the exceptions provided in Stipulation Section 3.8.4, these adjustment restrictions do not apply to the Company's calculated pension and OPEB internal reserves as of March 31, 2006.

post-employment benefit ("OPEB") was stated incorrectly. As corrected, that item should read as follows:

> 4) A reduction to pension/OPEB expense for the amounts capitalized will include credits for the normal capitalization of payroll, and intercompany billing revenues, but exclude credits for third party billing revenues. The amount of normal capitalization of payroll will be determined based on the process described above, and will be subject to adjustment annually based on a reconciliation as shown in Table 1. Third party and intercompany billing pension and OPEB revenue will be as actually realized and not subject to this annual reconciliation.

The undersigned counsel for Niagara Mohawk is authorized to state that all Signatories to Stipulation concur with the foregoing corrections.

Respectfully submitted,

NIAGARA MOHAWK POWER CORPORATION

d/b/a NATIONAL GRID

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Dated: April 17, 2007

June 2009 - May 2010 TARGETS

	SC6 (therms)	SC6 Target	SC6 MARGIN/THM	SC4 (therms)	SC4 Target	SC4 MARGIN/THM	SC4&SC6 Target	SC9 (therms)	SC 9 Target	TOTALS
Jun-2009	8,391,267	$ 396,761	$0.047283	290,674	$ 25,217	$0.086753	$421,978	15,265,791	$ 961,173	$1,383,151
Jul-2009	9,130,734	$ 431,725	$0.047283	290,674	$ 25,217	$0.086753	$456,942	29,522,051	$ 1,107,498	$1,564,439
Aug-2009	8,654,355	$ 409,200	$0.047283	290,674	$ 25,217	$0.086753	$434,417	39,041,787	$ 1,012,235	$1,446,652
Sep-2009	8,353,403	$ 394,971	$0.047283	290,674	$ 25,217	$0.086753	$420,187	30,748,253	$ 1,055,884	$1,476,071
Oct-2009	8,262,285	$ 390,662	$0.047283	549,260	$ 47,650	$0.086753	$438,312	21,794,869	$ 938,223	$1,376,535
Nov-2009	8,262,285	$ 390,662	$0.047283	702,620	$ 60,954	$0.086753	$451,616	11,964,174	$ 881,327	$1,332,943
Dec-2009	8,262,285	$ 390,662	$0.047283	910,273	$ 78,968	$0.086753	$469,631	38,071,380	$ 948,108	$1,417,739
Jan-2010	8,262,285	$ 390,662	$0.047283	1,020,536	$ 88,534	$0.086753	$479,196	13,374,046	$ 823,034	$1,302,230
Feb-2010	8,262,285	$ 390,662	$0.047283	910,273	$ 78,968	$0.086753	$469,631	28,562,763	$ 884,920	$1,354,551
Mar-2010	8,407,970	$ 397,551	$0.047283	812,324	$ 70,471	$0.086753	$468,022	30,413,764	$ 1,057,695	$1,525,717
Apr-2010	8,262,285	$ 390,662	$0.047283	593,477	$ 51,486	$0.086753	$442,148	12,116,827	$ 898,864	$1,341,011
May-2010	8,262,285	$ 390,662	$0.047283	290,674	$ 25,217	$0.086753	$415,879	6,738,010	$ 811,333	$1,227,212
TOTAL TO DATE	**100,773,721**	**4,764,844**	**$0.047283**	**6,952,133**	**$603,115**	**$0.086753**	**$5,367,959**	**277,613,713**	**$11,380,293**	**$16,748,252**
12 MTH TOTAL	**100,773,721**	**$4,764,844**	**$0.047283**	**6,952,133**	**$603,115**	**$0.086753**	**$5,367,959**	**277,613,713**	**$11,380,293**	**$16,748,252**

Illustrative June 2009 - May 2010 ACTUALS

	SC6 (therms)	SC6 Margin	SC6 MARGIN/THM	SC4 (therms)	SC4 Margin	SC4 MARGIN/THM	SC4&SC6 Margin	SC9 (therms)	SC 9 Margin	TOTALS
Jun-09	7,080,192	$ 334,334	$0.047221	123,214	$ 11,346	$0.092082	$ 345,680	13,067,201	$ 1,678,784	$2,024,463
Jul-09	7,371,732	$ 345,486	$0.046866	235,580	$ 15,223	$0.064618	$ 360,709	20,311,870	$ 972,700	$1,333,409
Aug-09	6,506,502	$ 306,566	$0.047117	256,625	$ 22,875	$0.089136	$ 329,441	11,539,771	$ 909,062	$1,238,503
Sep-09	7,286,640	$ 350,039	$0.048038	382,309	$ 33,757	$0.088297	$ 383,795	34,075,015	$ 1,038,412	$1,422,207
Oct-09	8,634,427	$ 404,466	$0.046843	482,364	$ 42,508	$0.088124	$ 446,974	33,305,130	$ 1,005,185	$1,452,158
Nov-09	9,079,701	$ 430,492	$0.047413	781,064	$ 69,359	$0.088800	$ 499,851	11,219,926	$ 935,284	$1,435,134
Dec-09	13,707,588	$ 640,250	$0.046708	1,106,531	$ 98,722	$0.089218	$ 738,972	59,292,709	$ 2,587,128	$3,326,100
Jan-10	6,199,606	$ 305,491	$0.049276	653,428	$ 56,285	$0.086139	$ 361,777	19,853,633	$ 1,039,416	$1,401,192
Feb-10	8,764,101	$ 421,321	$0.048074	1,096,065	$ 95,028	$0.086699	$ 516,349	16,802,193	$ 1,071,334	$1,587,683
Mar-10	9,186,798	$ 428,892	$0.046686	1,030,316	$ 88,445	$0.085842	$ 517,337	17,659,533	$ 1,047,444	$1,564,780
Apr-10	9,494,624	$ 447,719	$0.047155	449,562	$ 38,465	$0.085562	$ 486,184	21,068,967	$ 883,996	$1,370,180
May-10	7,642,099	$ 358,312	$0.046887	360,844	$ 31,604	$0.087583	$ 389,916	6,562,344	$ 956,283	$1,346,199
TARGETS TO DATE	**100,773,721**	**$ 4,764,844**		**6,952,133**	**$ 603,115**		**$ 5,367,959**	**277,613,713**	**$ 11,380,293**	**$ 16,748,252**
TOTAL ACTUAL REVENUE	**100,954,010**	**$ 4,773,369**	**0.047283**	**6,957,902**	**$ 603,615**	**$0.086752**	**$ 5,376,984**	**264,758,292**	**$ 14,125,026**	**$ 19,502,010**
(OVER)/UNDER	**(180,289)**	**$ (8,524.82)**		**(5,769)**	**$ (500.13)**		**$ (9,024.95)**	**12,855,421**	**$ (2,744,733.07)**	**$ (2,753,758.02)**
REVENUE SHARING BEFORE ADJUSTMENTS							**$ (9,024.95)**		**$ (2,744,733.07)**	**$ (2,753,758.02)**
ADJUSTMENT, RULE 26.3.2 PER PSC 219 (SC8 TO SC9)									**$ -**	**$ -**
ADJUSTMENT, RULE 26.3.3 PER PSC 219 (SC9 TO SC8)									**$ (551,747.29)**	**$ (551,747.29)**
ADJUSTMENT, RULE 26.3.4 PER PSC 219 (New SC9 Contracts with no Pre existing facilities)									**$ -**	**$ -**
ADJUSTMENT, RULE 26.3.5 PER PSC 219 (50% SHORTFALL ADJUSTMENT FOR RENEGOTIATED SC9 CONTRACT, CUSTOMER NO. 8)									**$ (234,834.61)**	**$ (234,834.61)**
SHARING PERCENTAGE (SYMMETRICAL)							**90%**		**100%**	
RESULTING AMOUNT (OVER) / UNDER RECOVERED							**$ (8,122.45)**		**$ (3,531,314.97)**	**$ (3,539,437.42)**

June 2009 - May 2010 Amount to be Recovered	$ (3,539,437.42)
September 2007 - August 2008 Balance to be Recovered	$ 300,000.00
Total Amount to be Refunded	($3,239,437.42)
Estimated SC1,2,&3 Sales and Delivery Only Thruput For the period September 1, 2010 - August 31, 2011	731,670,770
Estimated Surcharge / (Credit) Rate Per Therm	**($0.00443)**

Case 08-G-0609 Gas Sales for Resales and Capacity Release Example

Deferral Accounting: *Activity :* *254512*
WO: *9940004950*

Month	Customer	Transaction type	Account	Gross Revenue	DT's Sold	G/R Taxes Booked	Sale Price Without Franchise	Gas Cost *	Margin	Customer Share of Margin	Shareholder Share of Margin
Month 1	**Tenaska**	**Sales for Resale**	495400	$ 720,192	$ 125,924	$ -	$ 720,192	$ 714,124	$ 6,068	$ 5,157	$ 910
Month 1	**Tenaska**	**Capacity Release**	804000						$ 64,787	**$ 55,069**	**$ 9,718**
Total Month1				**$ 720,192**	**$ 125,924**	**$ -**	**$ 720,192**	**$ 714,124**	**$ 70,854**	**$ 60,226**	**$ 10,628**
Month 2	**Tenaska**	**Sales for Resale**	495400	$ 2,601,604	$ 378,576	$ -	$ 2,601,604	$ 2,565,967	$ 35,637	$ 30,292	$ 5,346
Month 2	**Tenaska**	**Capacity Release**	804000						$ 66,946	**$ 56,904**	**$ 10,042**
Total Month 2				**$ 2,601,604**	**$ 378,576**	**$ -**	**$ 2,601,604**	**$ 2,565,967**	**$ 102,584**	**$ 87,196**	**$ 15,388**
Month 3	**Tenaska**	**Sales for Resale**	495400	7,911,661.95	1,016,669	0.00	7,911,661.95	7,679,872.44	231,789.51	$ 197,021.08	$ 34,768.43
Month 3	**Tenaska**	**Capacity Release**	804000						0.00	**$0.00**	**$0.00**
Total Month 3				**$ 7,911,661.95**	**$ 1,016,669**	**$ -**	**$ 7,911,662**	**$ 7,679,872**	**$ 231,790**	**$ 197,021**	**$ 34,768**
Adj Month 3	**Tenaska**	**Sales for Resale**	495400	(2,821.70)	0.00	0.00	(2,821.70)	(2,363.99)	(457.71)	$ (389.05)	$ (68.66)
Month 4	**Tenaska**	**Sales for Resale**	495400	9,777,504.32	1,095,959	0.00	9,777,504.32	8,542,862.34	1,234,641.98	$ 1,049,445.68	$ 185,196.30
Month 4	**Tenaska**	**Capacity Release**	804000						0.00	**$0.00**	**$0.00**
Total Month 4				**$ 9,774,682.62**	**1,095,959**	**$ -**	**$ 9,774,683**	**$ 8,540,498**	**$ 1,234,184**	**$ 1,049,057**	**$ 185,128**
Adj Month 4	**Tenaska**	**Sales for Resale**	495400	58,536.13	0.00	0.00	58,536.13	71,591.41	(13,055.28)	$ (11,096.99)	$ (1,958.29)
Month 5	**Tenaska**	**Sales for Resale**	495400	7,292,142.00	774,955	0.00	7,292,142.00	6,463,832.86	828,309.14	$ 704,062.77	$ 124,246.37
Month 5	**Tenaska**	**Capacity Release**	804000						0.00	**$0.00**	**$0.00**
Total Month 5				**$ 7,350,678.13**	**774,955**	**0.00**	**$ 7,350,678**	**$ 6,535,424**	**$ 815,254**	**$ 692,966**	**$ 122,288**
Adj Month 5	**Tenaska**	**Sales for Resale**	495400	398,517.00	24,040	0.00	398,517.00	377,836.07	20,680.93	$ 17,578.79	$ 3,102.14
Month 6	**Tenaska**	**Sales for Resale**	495400	12,628,848.91	1,209,329	0.00	12,628,848.91	11,701,862.45	926,986.46	$ 787,938.49	$ 139,047.97
Month 6	**Tenaska**	**Capacity Release**	804000						0.00	**$0.00**	**$0.00**
Total Month 6				**$ 13,027,365.91**	**1,233,369**	**$ -**	**$ 13,027,365.91**	**$ 12,079,698.52**	**$ 947,667.39**	**$ 805,517.28**	**$ 142,150.11**
Month 7	**Tenaska**	**Sales for Resale**	495400	$ 7,827,638.43	1,016,976	0.00	7,827,638.43	7,240,080.38	587,558.05	$ 499,424.34	$ 88,133.71
Month 7	**Tenaska**	**Capacity Release**	804000						0.00	**$0.00**	**$0.00**
Total Month 7				**$ 7,827,638.43**	**1,016,976**	**$ -**	**$ 7,827,638.43**	**$ 7,240,080.38**	**$ 587,558.05**	**$ 499,424.34**	**$ 88,133.71**
Month 8	**Tenaska**	**Sales for Resale**	495400	$ 2,538,275.52	232,588	0.00	2,538,275.52	2,503,453.72	34,821.80	$ 29,598.53	$ 5,223.27
Month 8	**Tenaska**	**Capacity Release**	804000						79,359.60	$ 67,455.66	$ 11,903.94
Total Month 8				**$ 2,538,275.52**	**232,588**	**$ -**	**$ 2,538,275.52**	**$ 2,503,453.72**	**$ 114,181.40**	**$ 97,054.19**	**$ 17,127.21**
Adj Month 8	**Tenaska**	**Sales for Resale**	495400	206,817.51	20,000	0.00	206,817.51	225,017.94	(18,200.43)	(15,470.37)	(2,730.06)
Month 9	**Tenaska**	**Sales for Resale**	495400	436,825.00	36,500	0.00	436,825.00	435,540.00	1,285.00	1,092.25	192.75
Month 9	**Tenaska**	**Capacity Release**	804000						82,004.92	**$69,704.18**	**$12,300.74**
Total Month 9				**$ 643,642.51**	**56,500**	**$ -**	**$ 643,642.51**	**$ 660,557.94**	**$ 65,089.49**	**$ 55,326.07**	**$ 9,763.42**

Case 08-G-0609 Gas Sales for Resales and Capacity Release Example

Deferral Accounting: *Activity :* *254512*
WO: *9940004950*

Month	Customer	Transaction type	Account	Gross Revenue	DT's Sold	G/R Taxes Booked	Sale Price Without Franchise	Gas Cost *	Margin	Customer Share of Margin	Shareholder Share of Margin
Month 10	**Tenaska**	**Sales for Resale**	495400	94,187.50	7,500	0.00	94,187.50	94,125.00	62.50	53.13	9.38
Month 10	**Tenaska**	**Capacity Release**	804000						84,159.60	**$71,535.66**	**$12,623.94**
Total Month 10				**$ 94,187.50**	**7,500**	**$ -**	**$ 94,187.50**	**$ 94,125.00**	**$ 84,222.10**	**$ 71,588.79**	**$ 12,633.32**
Adj Month 10	**Tenaska**	**Sales for Resale**	495400	0.00	0	0.00	0.00	(66.00)	66.00	**56.10**	9.90
Month 11	**Tenaska**	**Sales for Resale**	495400	13,244,328.50	1,043,600	0.00	13,244,328.50	13,165,557.50	78,771.00	**66,955.35**	11,815.65
Month 11	**Tenaska**	**Capacity Release**	**804000**						82,004.92	**$69,704.18**	**$12,300.74**
Total Month 11				**$ 13,244,328.50**	**1,043,600**	**$ -**	**$ 13,244,328.50**	**$ 13,165,491.50**	**$ 160,841.92**	**$ 136,715.63**	**$ 24,126.29**
Adj for Month 11	**Tenaska**	**Sales for Resale**	495400	762,075.00	69,000	0.00	762,075.00	756,845.00	5,230.00	**4,445.50**	784.50
Month 12	**Tenaska**	**Sales for Resale**	495400	8,822,248.00	967,000	0.00	8,822,248.00	8,755,535.40	66,712.60	**56,705.71**	10,006.89
Month 12	**Tenaska**	**Capacity Release**	**804000**						102,396.72	**$87,037.21**	**$15,359.51**
Total Month12				**$ 9,584,323.00**	**1,036,000**	**$ -**	**$ 9,584,323.00**	**$ 9,512,380.40**	**$ 174,339.32**	**$ 148,188.42**	**$ 26,150.90**
Total Twelve Months Example				**75,318,580.63**				**$ 71,291,674**	**$ 4,588,566**	**$ 3,900,281**	**$ 688,285**
										85%	**15%**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
PSC Case No. 08-G-0609

Deferral of Regulatory, Legislative and Accounting Changes
($000's)

Line			2 Year Settlement Agreement: Rate Plan Year 1 12 months Ending May 19, 2010	2 Year Settlement Agreement: Rate Plan Year 2 12 months Ending May 19, 2011	In the event of a stay-out period: Rate Plan Year 3 Assume New Rates eff May 20, 2012	In the event of a stay-out period: Rate Plan Year 4 (partial) Assume New Rates eff Oct. 1, 2012
1						
	Step 1:	**Determination of Threshold (per Joint Proposal)**				"Stub" period May 20, 2012 to Sept 30, 2012
2		Operating Income After Taxes (before Interest)	$ 79,252			
3		Interest expense	33,602			
4		Operating Income After Interest and Taxes	45,650			
5			5.0%			
6		After-tax Threshold for All Years	$ 2,283	$ 2,283	$ 2,283	$ 2,283

Line							
	Step 2:	**Identify after-tax impact of a specific change - Increase (Decrease) to Net Income After Tax**					
			EXAMPLE #1:			EXAMPLE #3:	
7		Example: NYS reduction in Payroll Tax rates	$ 5,000 *		Example: One-time $15,000 NYS fee in May 2012	$ (9,194) *	= $15,000 x 19/31 May pro-ration required
8		Income tax impact	(1,981)			3,642	
9		After tax net income impact	$ 3,019			$ (5,552)	
10	**Step 3:**	Does after-tax impact exceed threshold ? Y/N	Yes			Yes	
11	**Step 4:**	Owed to Ratepayers or Company	owed to Ratepayers			owed to Company	
12	**Step 5:**	Is this subject to the excess Earnings test ?	No			Yes	
13	**Step 6:**	Pre-tax Excess (Under) Earnings	not applicable			1,000	<--- Ex: Co. Over Earning
14	**Step 7:**	Pre-tax amount to be deferred	$ (5,000)			$ -	not eligible, Co. is Over Earning
			EXAMPLE #2:			EXAMPLE #4:	
15		Example: NYS increases Payroll Tax rates	$ (5,000) *		Example: One-time $15,000 NYS fee in Sept. 2012	$ (15,000) *	
16		After tax net income impact	(3,019)			(9,058)	
17		Exceed threshold & to whom is money owed ?	Yes, owed to Company			Yes, owed to Company	
18		Pre-tax Excess (Under) Earnings	(1,500)	<--- Ex: Co. Under Earning		(10,000)	<--Ex: Under Earning in "Stub" period
19		Pre-tax amount to be deferred	$ 1,500	limited deferral		$ 9,058	full deferral

*** If an actual expense or benefit attributed to a specific change occurs in a month in which the rates developed in this Settlement are only partially in effect, than the expense or benefit may have to be pro-rated (based on number of days) for the month, and compare to the appropriate net income threshold for that period.**

1 This deferral is measured on an Rate Plan Year (May 20 to May 19). Note * above, indicates that pro-ration may need to be done in the month of May.
2 Appendix A, Statement of Gas Operating Income. Note: since any updates for Year 2 will be offsetting (i.e. higher expense & higher revenue rwuirement), the Year 1 threshold applies to all years.
3 Appendix A, Tax Deduction for Interest Expense. Note: since there are no updates to Capital Structure or Rate Base, the Interest Expense remains unchanged until after the next effective rate filing.
4 Line 1 - line 2
5 5.0% threshold, per Case 08-G-0609 Settlement.
6 Line 4 x line 5 This becomes the threshold for all years.
7 Example only
8 Based on Federal tax rate 35.0% and NYS tax rate 7.1% (note Federal gets a deduction for NYS, 35.0% x 7.1%)
9 Line 7 - line 8
10 Is line 9 greater in absolute terms than line 6 (Y/N)
11 An increase in net income is owed back to Ratepayers, and a decrease to income is owed to the Company
12 Amts owed to the Company are limited to the amount of Excess Earnings in that year. Amts owed tp Ratepayers are not subject this limitation.
13 Utilize the one year Earnings result (year in which "the specific change" occurs) from the Gas Earnings Sharing calculation. For this purpose, the Company is in an "Excess" Earnings position if actual ROE exceeds 10.2% ROE. If new rates become effective part way through a Rate Plan Year, the Earnings result for that "Stub" period as calculated in the Gas Earnings Sharing Report will be used.
14 Line 7 - line 13 if applicable (as note 12 above states, the Excess Earnings limit is only applicable to amounts owed to the Company).

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Deferral of Site Investigation and Remediation ("SIR") Costs
($000's)

Line	**Step 1: Determination of SIR Target**		Rate Plan Year 1 Ending May 19, 2010		**Example** Rate Plan Year 2 Ending May 19, 2011 and duration of any Stay-out
1	Forecasted SIR Expenses Forecast (EP-1, Schedule 45)		$ 4,500.0		$ 4,594.5
2	Forecasted Labor Included in SIR Expenses (EP-1, Schedule 29, Sheet 4):				
3	Forecasted Total SIR Labor Charged to Company 36	$ 480.6		$ 500.0	
4	Gas Allocation per MJP	15.0%		15.0%	
5	Forecasted Gas SIR Labor Allocated to Company 36		72.1		75.0
6	Forecasted SIR Expenses Forecast Excluding Labor*		$ 4,427.9		$ 4,519.5

* Niagara Mohawk shall include in the Deferral Account any SIR Costs allocated to gas operations paid in excess or below this amount per year.

Step 2: Calculation of Deferral (Gas Portion ONLY)

Line	**EXAMPLE 1 (No Change in Employee Count)**		Rate Plan Year 1 Ending May 19, 2010		Rate Plan Year 2 Ending May 19, 2011 and for the duration of any Stay-out
7	Forecasted SIR Expenses Forecast Excluding Labor		$ 4,427.9		$ 4,519.5
8	Actual Costs by Year:				
9	Labor (Total 11 Employees)	$ 75.0		$ 72.0	
10	Consultants	2,200.0		2,100.0	
11	Contractors	1,800.0		2,000.0	
12	Employee Expenses	7.0		7.0	
13	Hardware	0.2		0.1	
14	Other	500.0		200.0	
15	Materials	9.5		9.5	
16	Transportation	2.8		2.8	
17	Sub-Total Excluding Labor		4,519.5		4,319.4
18	Deferred Amount (Sub-Total above (below) Forecast)		$ 91.6 **		$ (200.1) **

Line	**EXAMPLE 2 (Change in Employee Count - Contractors and/or Consultants Displacing NMPC Employees) *****		Rate Year One Ending March 31, 2010		Rate Year Two Ending March 31, 2011 and for the duration of any Stay-out
19	Forecasted SIR Expenses Forecast Excluding Labor		$ 4,427.9		$ 4,519.5
20	Actual Costs by Year:				
21	Labor (Total 10 Employees)		$ 50.0		$ 46.0
22	Consultants		2,200.0		2,100.0
23	Contractors:				
24	Total Contractor Spending	1,825.0		2,026.0	
25	Incremental Contractor Used instead of NMPC Employee	25.0		26.0	
26	Net Contractor Spending		1,800.0		2,000.0
27	Employee Expenses		7.0		7.0
28	Hardware		0.2		0.1
29	Other		500.0		200.0
30	Materials		9.5		9.5
31	Transportation		2.8		2.8
32	Sub-Total Excluding Labor		4,519.5		4,319.4
33	Deferred Amount (Sub-Total above (below) Forecast)		$ 91.6 **		$ (200.1) **

**** In the month of May, both the actual SIR expense and the appropriate Forecast target (amount in rattes), will have to be pro-rated based on number of days.**
***** only applies to normal administrative, non-program type work**

Notes (by Line Number):

Line	Note
1	Input: Forecasted Year One SIR Expenses Forecast (Source: EP-1, Sched 45) Year Two and beyond, will be based on Year One actual.
3	Input: Forecasted Total SIR Labor Charged to Company 36 (Source: EP-1, Schedule 29, Sheet 4)
4	Input: Gas Allocation per MJP
5	Line 3 * Line 4
6	Line 1 - Line 5
7	Line 6
8	Title Line
9	Input: Actual Costs
10	Input: Actual Costs
11	Input: Actual Costs
12	Input: Actual Costs
13	Input: Actual Costs
14	Input: Actual Costs
15	Input: Actual Costs
16	Input: Actual Costs
17	Line 10 + Line 11 + Line 12 + Line 13 + Line 14 + Line 15 + Line 16
18	Line 17 - Line 7
19	Line 6
20	Title Line
21	Input: Actual Costs
22	Input: Actual Costs
23	Input: Actual Costs
24	Input: Actual Costs
25	Input: Actual Costs
26	Line 24 - Line 25
27	Input: Actual Costs
28	Input: Actual Costs
29	Input: Actual Costs
30	Input: Actual Costs
31	Input: Actual Costs
32	Line 22 + Line 26 + Line 27 + Line 28 + Line 29 + Line 30 + Line 31
33	Line 32 - Line 19

Reconciliation of Gas Supply Procurement Costs
Case 08-G-0608

Annual Target

			Therms	
Year 1	Dollars to be Recovered	$ 1,064,825	542,927,136	$ 0.00196

	Assumed Actual Thruput		**Dollars actually Recovered**
Dollars Actually Recovered			
June-09	15,708,629	$ 0.00196	$ 30,809
July-09	8,186,787	$ 0.00196	$ 16,056
August-09	6,197,534	$ 0.00196	$ 12,155
September-09	9,476,425	$ 0.00196	$ 18,586
October-09	24,298,278	$ 0.00196	$ 47,655
November-09	43,259,759	$ 0.00196	$ 84,844
December-09	70,949,879	$ 0.00196	$ 139,152
January-10	94,678,437	$ 0.00196	$ 185,690
February-10	93,433,176	$ 0.00196	$ 183,247
March-10	82,852,525	$ 0.00196	$ 162,496
April-10	61,265,770	$ 0.00196	$ 120,158
May-10	18,747,141	$ 0.00196	$ 36,768
	529,054,340		
Dollars Actually Recovered- June, 2009 through May, 2010			$ 1,037,616
Resulting Under-Recovery			$ 27,208

			Therms	
Year 2	Dollars to be Recovered	$ 1,064,825	525,488,858	$ 0.00203

	Assumed Actual Thruput		Dollars actually Recovered
Dollars Actually Recovered			
June-10	14,603,522	$ 0.00203	$ 29,645
July-10	10,313,123	$ 0.00203	$ 20,936
August-10	7,689,930	$ 0.00203	$ 15,611
September-10	8,481,881	$ 0.00203	$ 17,218
October-10	16,758,912	$ 0.00203	$ 34,021
November-10	35,055,398	$ 0.00203	$ 71,162
December-10	67,346,808	$ 0.00203	$ 136,714
January-11	95,068,642	$ 0.00203	$ 192,989
February-11	96,685,625	$ 0.00203	$ 196,272
March-11	87,576,428	$ 0.00203	$ 177,780
April-11	62,758,741	$ 0.00203	$ 127,400
May-11	33,659,627	$ 0.00203	$ 68,329
	535,998,635		
Dollars Actually Recovered- June, 2010 through May, 2011			$ 1,088,077
Resulting Over-Recovery			$ (23,253)

				Therms		
Year 3	Dollars to be Recovered	$	1,064,825			
	Under-recovery - TME May 2010	$	27,208			
	Total Dollars to be recovered	$	1,092,033	523,543,708	$	0.00209

	Assumed Actual Thruput				Dollars actually Recovered
Dollars Actually Recovered					
June-11	14,265,299	$	0.00209	$	29,814
July-11	9,635,865	$	0.00209	$	20,139
August-11	7,134,870	$	0.00209	$	14,912
September-11	7,923,819	$	0.00209	$	16,561
October-11	15,623,511	$	0.00209	$	32,653
November-11	34,457,533	$	0.00209	$	72,016
December-11	63,351,019	$	0.00209	$	132,404
January-12	90,855,470	$	0.00209	$	189,888
February-12	92,499,677	$	0.00209	$	193,324
March-12	85,385,146	$	0.00209	$	178,455
April-12	59,794,063	$	0.00209	$	124,970
May-12	31,992,304	$	0.00209	$	66,864
	512,918,576				
Dollars Actually Recovered- June, 2011 through May, 2012				$	1,072,000
Resulting Under-Recovery				$	20,033

PSC No. 219 Gas
Company: Niagara Mohawk Power Corporation d/b/a National Grid
Initial Effective Date: 5/20/2009

Statement Type: MFC
Statement No. 1

Merchant Function Charge
with Updated Gas Costs - 12/28/2008
Effective with Usage on or after the effective date of this statement and thereafter until changed

		SC1	SC2	SC2	SC12 Distributed Generation	SC13 Distributed Generation
		Residential $ Per Therm	Residential & Commercial $ Per Therm	Industrial $ Per Therm	Non-Residential $ Per Therm	Residential $ Per Therm
	Monthly Gas Supply Charge Forecast for Rate Year TME March 2010	$ 0.8426	$ 0.8420	$ 0.8030	$ 0.7645	$ 0.8066
	Uncollectible Factor	2.30%	0.30%	0.30%	0.30%	0.30%
1	Uncollectible Charge (Monthly Gas Supply Charge * Uncollectible Factor)	$ 0.01938	$ 0.00253	$ 0.00241	$ 0.00229	$ 0.00242
2	Gas Supply Procurement	$ 0.00196	$ 0.00196	$ 0.00196	$ 0.00196	$ 0.00196
3	Records and Collection Charge	$ 0.00419	$ 0.00419	$ 0.00419	$ 0.00419	$ 0.00419
4	Gas Storage Inventory Carrying Charge	$ 0.01241	$ 0.01241	$ 0.01241	$ 0.01241	$ 0.01241
Sum 1-4	Total Merchant Function Charge	$ 0.03794	$ 0.02109	$ 0.02097	$ 0.02086	$ 0.02098

GAS STORAGE INVENTORY

Gas Storage Inventory

DTI_GSS		Forecast Apr-09	Forecast May-09	Forecast Jun-09	Forecast Jul-09	Forecast Aug-09	Forecast Sep-09	Forecast Oct-09	Forecast Nov-09	Forecast Dec-09	Forecast Jan-10	Forecast Feb-10	Forecast Mar-10
Dth													
	Beginning Inventory	974,049	1,948,098	4,707,903	7,630,050	10,227,513	12,824,977	14,610,733	15,379,079	14,738,284	11,213,912	7,208,943	3,844,770
	Adjustments												
	Marketer Transfers												
	Injections	974,049	2,759,805	2,922,147	2,597,463	2,597,464	1,785,756	768,346	-	-	-	-	-
	Withdrawals	-	-	-	-	-	-	-	(640,795)	(3,524,372)	(4,004,969)	(3,364,173)	(2,883,576)
	Park, Loans, Transfers												
	EndingBalance	1,948,098	4,707,903	7,630,050	10,227,513	12,824,977	14,610,733	15,379,079	14,738,284	11,213,912	7,208,943	3,844,770	961,192
$													
	Beginning Inventory	$ 10,728,556	$ 17,088,521	$ 35,235,261	$ 54,726,761	$ 72,361,744	$ 90,220,536	$ 102,581,540	$ 107,993,439	$ 103,493,712	$ 78,745,217	$ 50,621,922	$ 26,998,361
	Adjustments												
	Marketer Transfers												
	Injections	$ 6,359,965	$ 18,146,741	$ 19,491,500	$ 17,634,983	$ 17,858,792	$ 12,361,004	$ 5,411,899	$ -	$ -	$ -	$ -	$ -
	Withdrawals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,499,727)	$ (24,748,494)	$ (28,123,295)	$ (23,623,561)	$ (20,248,775)
	Park, Loans, Transfers												
	EndingBalance	$ 17,088,521	$ 35,235,261	$ 54,726,761	$ 72,361,744	$ 90,220,536	$ 102,581,540	$ 107,993,439	$ 103,493,712	$ 78,745,217	$ 50,621,922	$ 26,998,361	$ 6,749,587
	Average Rate	$ 8.7719	$ 7.4843	$ 7.1725	$ 7.0752	$ 7.0348	$ 7.0210	$ 7.0221	$ 7.0221	$ 7.0221	$ 7.0221	$ 7.0221	$ 7.0221

Rate Plan Year 1 Amount recovered in Merchant Function Charge

Forecast Gas Storage Inventory
Updated 12/28/08

		Dth		$
Forecast Storage Balance at	April 1st (1/2)	974,049	$	5,364,278
	April 30st 2009	1,948,098	$	17,088,521
	May-2009	4,707,903	$	35,235,261
	Jun-2009	7,630,050	$	54,726,761
	Jul-2009	10,227,513	$	72,361,744
	Aug-2009	12,824,977	$	90,220,536
	Sep-2009	14,610,733	$	102,581,540
	Oct-2009	15,379,079	$	107,993,439
	Nov-2009	14,738,284	$	103,493,712
	Dec-2009	11,213,912	$	78,745,217
	Jan-2010	7,208,943	$	50,621,922
	Feb-2010	3,844,770	$	26,998,361
	03/01/2010 (1/2)	961,192	$	3,374,793
		106,269,503	$	748,806,087
11 and 2/2 Average Inventory Balance			$	62,400,507
Percentage to exclude SC3				99.0828212%
Avg inventory dollars w/o SC3			$	61,828,183
Pre-Tax Weighted Average Cost of Capital				10.69%
Resulting Carrying Charges			$	6,609,433

Twelve Months Ending March 2010 Therms

SC1	417,324,767
SC2	114,998,464
SC12	246,120
Total	532,569,351

Resulting Rate for Merchant Function Charge — $ 0.01241 Rate per therm w/o SC3 effective May 20, 2009- May 31st 2010

GAS STORAGE INVENTORY

Year 1 True-up

	Dekatherm	Actual Rate Per Dth for Plan Year	Calculated Inventory Dollars
June 1st '(1/2)	4,707,903	$ 8.00	$ 18,831,612
Jun-2009	7,630,050	$ 7.50	$ 57,225,375
Jul-2009	10,227,513	$ 7.50	$ 76,706,348
Aug-2009	12,824,977	$ 7.50	$ 96,187,328
Sep-2009	14,610,733	$ 7.50	$ 109,580,498
Oct-2009	15,379,079	$ 7.00	$ 107,653,553
Nov-2009	14,738,284	$ 7.00	$ 103,167,988
Dec-2009	11,213,912	$ 7.00	$ 78,497,384
Jan-2010	7,208,943	$ 7.00	$ 50,462,601
Feb-2010	3,844,770	$ 7.00	$ 26,913,390
Mar-2010	961,192	$ 7.00	$ 3,364,172
Apr-2010	1,948,098	$ 8.00	$ 7,792,392
05//2010 (1/2)	4,707,903	$ 8.50	$ 20,008,588
	110,003,357		$ 736,382,640
11 and 2/2 Average			$ 61,365,220
SC3 Percentage			99.0828212%
Avg inventory dollars w/o SC3(actual)			$ 60,802,391
Avg inventory dollars w/o SC3 (Forecast)			$ 61,828,183
Change in Average Inventory Dollars			$ (1,025,792)
Pre-Tax WACC			**10.69%**
Resulting Carrying Charge Overcollection			(109,657)
Prior Year Dollars Collected Rate Per therm			$ 0.01241
Actual Thrutput- TME May 31, 2010			530,000,000
Actual Dollars Collected			$ 6,577,546
Dollars required to be collected			$ 6,609,433
Resulting Undercollection due to Thruput			$ 31,887
Total Variance due to Price and Sales Variance			$ (77,770)

Year 2 Forecast for Plan Year - June 1st, 2010

	Dekatherm	Rate Per Dth	Inventory Dollars
June 1st (1/2)	4,707,903	$ 10.00	$ 23,539,515
June 30th 2010	7,630,050	$ 9.00	$ 68,670,450
Jul-2010	10,227,513	$ 8.00	$ 81,820,104
Aug-2010	12,824,977	$ 8.20	$ 105,164,811
Sep-2010	14,610,733	$ 8.25	$ 120,538,547
Oct-2010	15,379,079	$ 8.26	$ 127,031,193
Nov-2010	14,738,284	$ 8.26	$ 121,738,226
Dec-2010	11,213,912	$ 8.26	$ 92,626,913
Jan-2011	7,208,943	$ 8.26	$ 59,545,869
Feb-2011	3,844,770	$ 8.26	$ 31,757,800
Mar-2011	961,192	$ 8.26	$ 7,939,446
Apr-2011	1,948,098	$ 8.26	$ 16,091,289
May 2011 (1/2)	4,707,903	$ 8.30	$ 19,537,797
	110,003,357		$ 876,001,961
11 and 2/2 Average			$ 73,000,163
SC3 Percentage			99.0828212%
Avg inventory dollars w/o SC3			$ 72,330,621
Pre-Tax Weighted Average Cost of Capital			**10.69%**
Resulting Carrying Charges			$ 7,732,143
Forecast SC 1,2 12 and 13 Thruput - TME May 2011		**Therms**	525,488,858
			$ 0.01471

Rate Adjustment effective September 1, 2010

Rate Plan Year 1 overcollection		$ (77,770)
Forecast SC 1, 2, 12 and 13 thruput- TME August 2012	**Therms**	525,191,051
Resulting Rate Per Therm Adjustment Necessary		$ (0.00015)
Rate Plan year 1 from above		$ 0.01471
Total Rate effective September 1, 2010		$ 0.01457

* Rate Case 08-G-0609- Gas Storage Inventory Rate Per therm component of Merchant Function Charge to be filed with PSC not later than July 31 of each year for modification in the Merchant Function Charge Rate Effective September 1st of each year- the first time period to be June 09- May 2010

** Process is reiterative; Year 2 update forecast becomes the base against which Year 2 actuals are compared and a new year 3 update is made.

Niagara Mohawk d/b/a National Grid
Case 08-G-0609
Reconciliation of Low Income Program Costs to Revenue Recovered
JP Sections 4.4.4 and 6.1

1) Year 1 Reconciliation - The Low Income Reconciliation for the first year will commence May 20, 2009 and end May 19th, 2010. An illustration of the Reconciliation of Low Income Program Costs to Low Income Revenue Recovered is shown on Sheets 2 and 3 of this Appendix L8:
    a. The actual revenue recovered for the period will be the result of the multiplication of the $.65 per customer embedded in base rates times the actual number of bills for SC1,2,3,4,5,6,7,8,12 and the NYSEG special contract. The calculation will reflect the pro-ration of the rate increase included in the billed revenue. A report will be generated by the billing system showing the actual low income revenue recovered taking into account the pro-ration percentage. The pro-ration percentage will reflect the number of days each batch contains after the effective date of new rates.
    b. Actual Discounts provided – The actual discounts provided to participants will be calculated by multiplying the $7.50 discount by the number of bills to which the discount is applied. The discounts will reflect the pro-ration of the discount in the billed revenue. A report will be generated by the billing system showing the actual discounts provided and the number of participants.
2) Reconciliations beginning Rate Plan Year 2 – The reconciliations will cover the period May 20th through May 19th. This reconciliation will commence May 20, 2010.

Niagara Mohawk Power Corporation d/b/a National Grid
Case 08-G-0609
Illustrative Example of Reconciliation of Low Income Program Costs Recovered In Rates
to actual costs of the Low Income Program *

Sections 4.4.4. and 6.1
Sheet 2 of 2

Year 1

Number of Customers	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8	Nyseg	SC12	
	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65	
05/20/2009-05/31/2009	532208	44700	33	2	158	23	660	54	1	1	577840
Jun-2009	531233	44441	32	2	158	23	660	53	1	1	576604
Jul-2009	530718	44295	31	2	158	23	660	55	1	1	575944
Aug-2009	529288	44416	36	2	167	23	660	55	1	1	574649
Sep-2009	529884	44403	36	2	163	23	660	54	1	1	575227
Oct-2009	531302	44615	35	2	159	23	660	54	1	1	576852
Nov-2009	533685	44904	34	2	157	23	660	54	1	1	579521
Dec-2009	534942	45093	33	2	157	23	660	54	1	1	580966
Jan-2010	536177	45122	32	2	157	23	660	54	1	1	582229
Feb-2010	536951	45170	32	2	158	23	660	54	1	1	583052
Mar-2010	536949	45128	32	2	158	23	660	54	1	1	583008
Apr-2010	531760	45518	47	2	167	22	640	54	1	1	578212
May-2010	530299	45310	47	2	167	22	640	54	1	1	576543

Revenue Recovered		SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8	Nyseg	SC12	Total
05/20/2009-05/31/2009	May-09	$ 345,935	$ 29,055	$ 21	$ 1	$ 103	$ 15	$ 429	$ 35	$ 1	$ 1	$ 375,596
Initial Month Proration Factor		3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	
Initial Dollars Collected		$ 11,540	$ 969	$ 1	$ 0	$ 3	$ 0	$ 14	$ 1	$ 0	$ 0	$ 12,530
Jun-2009		$ 345,301	$ 28,887	$ 21	$ 1	$ 103	$ 15	$ 429	$ 34	$ 1	$ 1	$ 374,793
Jul-2009		$ 344,967	$ 28,792	$ 20	$ 1	$ 103	$ 15	$ 429	$ 36	$ 1	$ 1	$ 374,364
Aug-2009		$ 344,037	$ 28,870	$ 23	$ 1	$ 109	$ 15	$ 429	$ 36	$ 1	$ 1	$ 373,522
Sep-2009		$ 344,425	$ 28,862	$ 23	$ 1	$ 106	$ 15	$ 429	$ 35	$ 1	$ 1	$ 373,898
Oct-2009		$ 345,346	$ 29,000	$ 23	$ 1	$ 103	$ 15	$ 429	$ 35	$ 1	$ 1	$ 374,954
Nov-2009		$ 346,895	$ 29,188	$ 22	$ 1	$ 102	$ 15	$ 429	$ 35	$ 1	$ 1	$ 376,689
Dec-2009		$ 347,712	$ 29,310	$ 21	$ 1	$ 102	$ 15	$ 429	$ 35	$ 1	$ 1	$ 377,628
Jan-2010		$ 348,515	$ 29,329	$ 21	$ 1	$ 102	$ 15	$ 429	$ 35	$ 1	$ 1	$ 378,449
Feb-2010		$ 349,018	$ 29,361	$ 21	$ 1	$ 103	$ 15	$ 429	$ 35	$ 1	$ 1	$ 378,984
Mar-2010		$ 349,017	$ 29,333	$ 21	$ 1	$ 103	$ 15	$ 429	$ 35	$ 1	$ 1	$ 378,955
Apr-2010		$ 345,644	$ 29,587	$ 31	$ 1	$ 109	$ 14	$ 416	$ 35	$ 1	$ 1	$ 375,838
Ending Dollars Collected		$ 333,196	$ 28,469	$ 30	$ 1	$ 105	$ 14	$ 402	$ 34	$ 1	$ 1	$ 362,251
Ending Month Proration Factor		96.7%	96.7%	96.7%	96.7%	96.7%	96.7%	96.7%	96.7%	96.7%	96.7%	
5/1/10 to 5/19/10 Dollars	May-2010	$ 344,694	$ 29,452	$ 31	$ 1	$ 109	$ 14	$ 416	$ 35	$ 1	$ 1	$ 374,753
Total Dollars Collected 5/20/09 - 05/31/2010		$ 4,155,614	$ 349,957	$ 277	$ 16	$ 1,252	$ 178	$ 5,122	$ 422	$ 8	$ 8	$ 4,512,853

Year 1

Discounts Provided		Number of Participants	Low Incom Credit	Dollars Credited
05/20/2009-05/31/2009	May-09	50.00		
Initial Month Proration Factor		3.3%		
Initial Dollars Collected		2	$ 7.50	$ 13
Jun-2009		10000	$ 7.50	$ 75,000
Jul-2009		20000	$ 7.50	$ 150,000
Aug-2009		30000	$ 7.50	$ 225,000
Sep-2009		40000	$ 7.50	$ 300,000
Oct-2009		50000	$ 7.50	$ 375,000
Nov-2009		55000	$ 7.50	$ 412,500
Dec-2009		60000	$ 7.50	$ 450,000
Jan-2010		65000	$ 7.50	$ 487,500
Feb-2010		50000	$ 7.50	$ 375,000
Mar-2010		40000	$ 7.50	$ 300,000
Apr-2010		50000	$ 7.50	$ 375,000
Ending Dollars Collected		38666	$ 7.50	$ 289,992
Ending Month Proration Factor		96.7%		
5/1/10 to 5/19/10 Dollars	May-2010	40000		
				$ 3,815,005

Year 1 Overcollection (undercollection) $ 697,848

* Revenue Recovered and credits provided will be reported automatically by the Company's billing system. A report will be created to report the accurate impact of proration and actual recoveries and credits

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Revenue Requirement Effect of Reconciliation of Actual Underspending of Capital Expenditures to Rate Case Forecast
For the Rate Year Ending March 31, 2010
($000's)

Line	Column	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Rate Year ending March 31,2010 Capital Expenditure Target inclusive of Bare Steel Services				$ 69,073,755						
2	Rate Year ended March 31,2010 Actual Capital Expenditure l inclusive of Bare Steel Services				$ 65,073,755						
3	Difference				$ 4,000,000						
4	Plant in service closings assuming a 3 month closing lag		Actual 3/31/10 Capital Expenditures below the Rate Year Forecast	Cumulative CWIP	Plant Closing	Cumlative Plant In Service	Depreciation Expense at Composite Rate	Cumlative Depreciation Reserve	Net Plant	Non-Interest bearing CWIP (NIBCWIP)	Total Plant in Service and NIBCWIP
	Net Plant and NIBCWIP @ 1/2 month bal	09-Mar	$ -	$ -	$ -	$ -			$ -	$ -	$ -
5		09-Apr	$ 333,333	$ 333,333	$ -	$ -			$ -	$ 92,867	$ 92,867
6		09-May	$ 333,333	$ 666,667	$ -	$ -			$ -	$ 185,733	$ 185,733
7		09-Jun	$ 333,333	$ 1,000,000	$ -	$ -			$ -	$ 278,600	$ 278,600
8		09-Jul	$ 333,333	$ 1,000,000	$ 333,333	$ 333,333	$ 621	$ 621	$ 332,713	$ 278,600	$ 611,313
9		09-Aug	$ 333,333	$ 1,000,000	$ 333,333	$ 666,667	$ 1,241	$ 1,862	$ 664,805	$ 278,600	$ 943,405
10		09-Sep	$ 333,333	$ 1,000,000	$ 333,333	$ 1,000,000	$ 1,862	$ 3,724	$ 996,276	$ 278,600	$ 1,274,876
11		09-Oct	$ 333,333	$ 1,000,000	$ 333,333	$ 1,333,333	$ 2,482	$ 6,206	$ 1,327,127	$ 278,600	$ 1,605,727
12		09-Nov	$ 333,333	$ 1,000,000	$ 333,333	$ 1,666,667	$ 3,103	$ 9,309	$ 1,657,357	$ 278,600	$ 1,935,957
13		09-Dec	$ 333,333	$ 1,000,000	$ 333,333	$ 2,000,000	$ 3,724	$ 13,033	$ 1,986,967	$ 278,600	$ 2,265,567
14		10-Jan	$ 333,333	$ 1,000,000	$ 333,333	$ 2,333,333	$ 4,344	$ 17,377	$ 2,315,956	$ 278,600	$ 2,594,556
15		10-Feb	$ 333,333	$ 1,000,000	$ 333,333	$ 2,666,667	$ 4,965	$ 22,342	$ 2,644,325	$ 278,600	$ 2,922,925
16	Net Plant and NIBCWIP @ 1/2 month bal	10-Mar	$ 333,333	$ 1,000,000	$ 333,333	$ 3,000,000	$ 5,586	$ 27,928	$ 1,486,036	$ 139,300	$ 1,625,336
17							$ 27,928		$ 1,117,630	$ 243,775	$ 1,361,405
18						Composite Depreciation rate	2.23%	Return at 10.69%	$ 119,475	$ 26,060	$ 145,534
19		($000's)									
20	Staff Gas Plant in Service Forecast for Rate Year Ending 3/31/10	$ 1,766,669						Revenue Requirement Impact	$ 147,402	$ 26,060	$ 173,462
21	Staff Gas Depreciation Expense Forecast for Rate Year Ending 3/31/10	$ 39,471									
22											
23	Composite Depreciation Rate	2.23%									
24	Non-Interest Bearing CWIP % from Staff Forecast	27.86%									

Notes (by line number

1 Forecast per page ? Line ? of JP
2 Actuals
3 Line 1,Col d - Line 2,Col d
4 Assumed zero -
5 line 5 to line 15, Col b = line 3, col d divided by 12
5 line 5 to line 15, Col c = Col b + previous line Col c - Col d
5 line 5 to line 15, Col d = +Col b repeat each line downward from line 5
5 line 5 to line 15, Col e = Col d + previous line Col e
6
7
8

NIAGARA MOHAWK POWER CORPORATION

WEIGHTED AVERAGE COST OF LONG-TERM DEBT
At December 31, 2007
($000)

Exhibit___(PP/KD-11)
page 1 of 2

LONG-TERM DEBT	RATE %	PRINCIPAL AMOUNT	ANNUAL INTEREST & FEES	ANNUAL AMORTIZATION DEBT DISCOUNT AND EXPENSE	TOTAL INTEREST AND ANNUAL AMORTIZATION	EFFECTIVE RATE
7.75% Series G Senior Notes	7.75%	600,000	46,500	1,352	47,852	7.98%
1991 Series A Pollution Control Revenue Bonds	4.35%	45,600	1,984	336	2,320	5.09%
1985 Series A Pollution Control Revenue Bonds	5.35%	100,000	5,350	300	5,650	5.65%
1988 Series A Pollution Control Revenue Bonds	4.90%	69,800	3,420	134	3,554	5.09%
5.15% Pollution Control Tax Exempt	5.15%	75,000	3,863	156	4,019	5.36%
1985 Series B Pollution Control Revenue Bonds	2.54%	37,500	951	90	1,041	2.78%
1985 Series C Pollution Control Revenue Bonds	4.30%	37,500	1,613	90	1,703	4.54%
1986 Series A Pollution Control Revenue Bonds	4.65%	50,000	2,325	80	2,405	4.81%
1987 Series A Pollution Control Revenue Bonds	4.30%	25,760	1,108	51	1,159	4.50%
1987 Series B-1 Pollution Control Revenue Bonds	4.85%	68,200	3,308	74	3,382	4.96%
1987 Series B-2 Pollution Control Revenue Bonds	4.95%	25,000	1,238	74	1,312	5.25%
2004 Series A Pollution Control Revenue Bonds	3.85%	115,705	4,455	301	4,756	4.11%
Note Payable to NMHI	5.80%	500,000	29,000	0	29,000	5.80%
Note Payable to NMHI	3.83%	350,000	13,405	0	13,405	3.83%
Note Payable to NMHI	3.72%	350,000	13,020	0	13,020	3.72%
Amortization of Reaquired Debt Call Premiums & DD&E				7,442	7,442	
		$2,450,065	**$131,537**	**$10,480**	**$142,017**	**5.80%**

Exhibit___(PP/KD-11)
page 2 of 2

NIAGARA MOHAWK POWER CORPORATION
ESTIMATED COST OF SENIOR SECURITIES

($000)

Estimated Cost of Long-Term Debt as of March 31, 2010	Principle Amount	Effective Rate	Total Interest and Annual Amortization
As of December 31, 2007	2,450,065	5.80%	$142,017
Variable Rate Changes:			
1991 Series A Pollution Control Revenue Bonds		0.71%	324
1985 Series A Pollution Control Revenue Bonds		-0.29%	(290)
1988 Series A Pollution Control Revenue Bonds		0.16%	112
1985 Series B Pollution Control Revenue Bonds		2.53%	947
1985 Series C Pollution Control Revenue Bonds		0.76%	285
1986 Series A Pollution Control Revenue Bonds		0.41%	205
1987 Series A Pollution Control Revenue Bonds		0.76%	196
1987 Series B-1 Pollution Control Revenue Bonds		0.21%	143
1987 Series B-2 Pollution Control Revenue Bonds		0.11%	28
2004 Series A Pollution Control Revenue Bonds		2.39%	2,765
Refundings:			
7.75% Series G Senior Notes Maturing on 10/1/08	(600,000)	7.98%	(47,852)
3.72% Note Payable To NMHI Maturing on 7/31/09	(233,014)	3.72%	(8,668)
New Issuances:			
6.70% 10 Year NMPC Note Issued on 10/01/08	750,000	6.90%	51,750
6.70% 10 Year NMPC Note Issued on 10/01/09	586,586	6.90%	40,474
Amortization of Reaquired Debt Call Premiums & DD&E			(866)
Total Long-Term Debt	**$2,953,638**	**6.15%**	**$181,569**

	Low End	High End	Allocation Factor	17.85%
Dead Band	6.75%	7.05%		

Day of Rate Year	Cumulative Projected Long-Term Debt Issuance	Actual Long-Term Debt Issued	Cumulative Long-Term Debt Issued	Projected Daily Long-Term Debt Coupon Rate (6.90%/360)	Actual Long-Term Debt Coupon Rate: Issue #1 Actual Coupon Rate	Issue #1 Daily Coupon Rate	Issue #2 Actual Coupon Rate	Issue #2 Daily Coupon Rate	Issue #3 Actual Coupon Rate	Issue #3 Daily Coupon Rate	Level of Short-Term Debt	Daily Short-Term Debt Interest Rate	Deferral A Daily	Deferral A Cumulative	Deferral B Daily	Deferral B Cumulative
	750,000,000.00 [1]	-														
1	750,000,000.00	-	0.00	0.019167%	0.00%	0.0000%	0.00%	0.0000%	0.00%	0.0000%	775,000,000.00	0.0083%	0.00	0.00	(14,503.13)	(14,503.13)
2	750,000,000.00	-	0.00	0.019167%	0.00%	0.0000%	0.00%	0.0000%	0.00%	0.0000%	770,000,000.00	0.0083%	0.00	0.00	(14,503.13)	(29,006.25)
3	750,000,000.00	-	0.00	0.019167%	0.00%	0.0000%	0.00%	0.0000%	0.00%	0.0000%	720,000,000.00	0.0083%	0.00	0.00	(13,923.00)	(42,929.25)
4	750,000,000.00	-	0.00	0.019167%	0.00%	0.0000%	0.00%	0.0000%	0.00%	0.0000%	775,000,000.00	0.0069%	0.00	0.00	(16,362.50)	(59,291.75)
5	750,000,000.00	250,000,000.00	250,000,000.00	0.019167%	7.55%	0.0210%	0.00%	0.0000%	0.00%	0.0000%	550,000,000.00	0.0069%	619.79	619.79	(10,908.33)	(70,200.08)
6	750,000,000.00	-	250,000,000.00	0.019167%	7.55%	0.0210%	0.00%	0.0000%	0.00%	0.0000%	600,000,000.00	0.0069%	619.79	1,239.58	(10,908.33)	(81,108.42)
7	750,000,000.00	-	250,000,000.00	0.019167%	7.55%	0.0210%	0.00%	0.0000%	0.00%	0.0000%	400,000,000.00	0.0090%	619.79	1,859.38	(7,239.17)	(88,347.58)
8	750,000,000.00	-	250,000,000.00	0.019167%	7.55%	0.0210%	0.00%	0.0000%	0.00%	0.0000%	450,000,000.00	0.0090%	619.79	2,479.17	(8,144.06)	(96,491.65)
9	750,000,000.00	-	250,000,000.00	0.019167%	7.55%	0.0210%	0.00%	0.0000%	0.00%	0.0000%	550,000,000.00	0.0090%	619.79	3,098.96	(9,048.96)	(105,540.60)
10	750,000,000.00	300,000,000.00	550,000,000.00	0.019167%	7.55%	0.0210%	6.45%	0.0179%	0.00%	0.0000%	600,000,000.00	0.0049%	173.54	3,272.50	(5,107.08)	(110,647.69)
11	1,250,000,000.00		550,000,000.00	0.019167%	7.55%	0.0210%	6.45%	0.0179%	0.00%	0.0000%	175,000,000.00	0.0049%	173.54	3,446.04	(4,468.70)	(115,116.39)
12	1,250,000,000.00		550,000,000.00	0.019167%	7.55%	0.0210%	6.45%	0.0179%	0.00%	0.0000%	50,000,000.00	0.0083%	173.54	3,619.58	(966.88)	(116,083.26)
13	1,250,000,000.00		550,000,000.00	0.019167%	7.55%	0.0210%	6.45%	0.0179%	0.00%	0.0000%	500,000,000.00	0.0083%	173.54	3,793.13	(9,668.75)	(125,752.01)
14	1,250,000,000.00		550,000,000.00	0.019167%	7.55%	0.0210%	6.45%	0.0179%	0.00%	0.0000%	750,000,000.00	0.0111%	173.54	3,966.67	(10,065.42)	(135,817.43)
15	1,250,000,000.00	750,000,000.00	1,300,000,000.00 [2]	0.019167%	7.55%	0.0210%	6.45%	0.0179%	7.20%	0.0200%	625,000,000.00	0.0083%	694.17	4,660.83	0.00	(135,817.43)
16	1,250,000,000.00		1,300,000,000.00	0.019167%	7.55%	0.0210%	6.45%	0.0179%	7.20%	0.0200%	250,000,000.00	0.0083%	694.17	5,355.00	0.00	(135,817.43)

1 Projected to be issued prior to the rate year

2 In the above example the rate deferral (deferral A) would occur for 100% of the first two issuances and for $700,000,000 of the third issuance

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
PSC Case No. 08-G-0609

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Deferral of PSC Assessment
($000's)

Rate Case Allowance (in all full years)						**$3,727,500**
Deferral will be measured for Rate Plan Year twelve months ending May 19 each year.						
EXAMPLE						
Final Bill (FYE 3/31/10)	$3,733,000	x	86.58%	=	$3,231,858	
Final Bill (FYE 3/31/11)	4,055,000	x	13.42%	=	544,370	
Final Bill (RYE 5/31/10)						$3,776,227
Deferral For RYE 5/19/10 (Regulatory debit is limited to Company under earning 10.2% ROE)						**$48,727**

Note: PSC assessment charges or refunds related to FYE 3/31/09 which fall into the RYE 5/19/10 (since final bill for preceding fiscal year ending March 31 is typically received around Nov. timeframe) do not factor into the PSC Assessment deferral calculation. The Company absorbs any such additional charge or retains any such additional refund.

Also note, the Final Bill for 5/31/10 will not likely be received until Nov. 2010. Therefore, estimated can be booked, but an adjustment will be needed for that Final Bill.

Deferral covers the Rate Plan Year period 5/20/09 - 5/19/10

5/20/09 - 3/31/10 = 316 days =	86.58%
4/01/10 - 5/19/10 = 49 days =	13.42%

Late Payment Charge True-up Proposal

Development of Amount of LPC Revenue currently in Base Rates

1) The current Staff Settlement Forecast contains $3.279 million of **existing** Late Payment Charge Revenue for the Rate Year TME March 31, 2010.
2) This amount can be broken down into $1.522 million related to Delivery, $1.711 million related to Commodity, and $0.047 million related to GRT using the LPC percentages by class which the $3.279 million is based on.
3) The $1.711 million related to Commodity can then be further broken down into $1.248 million for SC1 and $0.427 million for SC 2, and $.025 million for SC 3 customers. The remaining balance of $.010 million relates to SC 8 standby and has been excluded from this mechanism. These amounts stated by month("LPC Revenue in Base Rates") are set forth on the attached schedule.

Calculation of True-up to Amount in Base Rates

4) Starting in June 2009, "Assumed Actual LPC revenue" would then be calculated each month for SC1, SC 2 & SC3 by use of the monthly "Percent of Revenue"set forth on the attached schedule times the effective SC1,SC 2, SC3 Commodity Cost of Gas Rate times forecasted sales for the upcoming month(Calculated Commodity Revenue).
5) Each month for SC1 2, and 3, the resulting "Assumed Actual LPC revenue" would be compared to the "LPC Revenue in Base Rates."
6) The difference between the "LPC Revenue in Base Rates" and the "Assumed Actual LPC Revenue for each of the three rate groups would be refunded or surcharged to the respective Service Classification as a $/therm surcharge/refund via the Company's Delivery Service Adjustment Mechanism. These surcharge/refund volumetric rates, would be implemented commencing June 2009.

Case 08-G-0609 Late Payment Charge True-up Example

Percent of Revenue For LPC

Class	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
SC1	0.843%	0.695%	0.773%	0.542%	0.375%	0.259%	0.225%	0.272%	0.280%	0.322%	0.415%	0.711%
SC2	1.213%	1.007%	1.317%	0.913%	0.543%	0.295%	0.208%	0.289%	0.297%	0.358%	0.494%	0.979%
SC3	0.688%	0.418%	0.956%	0.962%	1.136%	0.518%	0.454%	0.690%	0.777%	0.851%	1.078%	0.672%

LPC Revenue in Base Rates

Class	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
SC1	$ 75,969	$ 30,062	$ 26,158	$ 28,529	$ 55,820	$ 73,102	$ 104,630	$ 171,398	$ 176,766	$ 178,087	$ 177,554	$ 149,991
SC2	$ 29,451	$ 17,085	$ 16,150	$ 17,021	$ 23,514	$ 21,548	$ 26,062	$ 50,407	$ 52,540	$ 56,414	$ 58,965	$ 58,169
SC3	$ 1,254	$ 702	$ 1,829	$ 1,925	$ 2,685	$ 1,448	$ 1,489	$ 2,556	$ 2,993	$ 3,061	$ 3,599	$ 1,670
Total	$ 106,674	$ 47,849	$ 44,137	$ 47,475	$ 82,018	$ 96,097	$ 132,180	$ 224,361	$ 232,299	$ 237,562	$ 240,118	$ 209,831

Assumed Commodity Revenue based on 10% increase in gas cost

Class	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
SC1	$ 9,908,277	$ 4,755,340	$ 3,720,850	$ 5,791,096	$ 16,369,474	$ 31,047,197	$ 51,106,930	$ 69,392,090	$ 69,493,387	$ 60,818,158	$ 47,073,739	$ 23,202,150
SC2	$ 2,671,158	$ 1,866,450	$ 1,348,601	$ 2,050,749	$ 4,764,279	$ 8,031,939	$ 13,789,171	$ 19,172,716	$ 19,478,810	$ 17,324,374	$ 13,129,870	$ 6,535,177
SC3	$ 200,404	$ 184,580	$ 210,590	$ 220,031	$ 259,945	$ 307,754	$ 361,019	$ 407,285	$ 423,676	$ 395,874	$ 367,408	$ 273,347
Total	$ 12,779,839	$ 6,806,370	$ 5,280,041	$ 8,061,875	$ 21,393,697	$ 39,386,890	$ 65,257,120	$ 88,972,091	$ 89,395,872	$ 78,538,406	$ 60,571,017	$ 30,010,673

Assumed Actual LPC Revenue

SC1	$ 83,566	$ 33,069	$ 28,773	$ 31,382	$ 61,402	$ 80,412	$ 115,093	$ 188,538	$ 194,442	$ 195,895	$ 195,309	$ 164,990
SC2	$ 32,396	$ 18,793	$ 17,765	$ 18,723	$ 25,865	$ 23,702	$ 28,668	$ 55,447	$ 57,794	$ 62,056	$ 64,862	$ 63,986
SC3	$ 1,379	$ 772	$ 2,012	$ 2,117	$ 2,953	$ 1,593	$ 1,638	$ 2,811	$ 3,292	$ 3,367	$ 3,959	$ 1,837
Total	$ 117,342	$ 52,634	$ 48,551	$ 52,223	$ 90,220	$ 105,707	$ 145,398	$ 246,797	$ 255,529	$ 261,318	$ 264,129	$ 230,814

(Refund)/Surcharge Revenues

SC1	$ (7,597)	$ (3,006)	$ (2,616)	$ (2,853)	$ (5,582)	$ (7,310)	$ (10,463)	$ (17,140)	$ (17,677)	$ (17,809)	$ (17,755)	$ (14,999)
SC2	$ (2,945)	$ (1,708)	$ (1,615)	$ (1,702)	$ (2,351)	$ (2,155)	$ (2,606)	$ (5,041)	$ (5,254)	$ (5,641)	$ (5,897)	$ (5,817)
SC3	$ (125)	$ (70)	$ (183)	$ (192)	$ (268)	$ (145)	$ (149)	$ (256)	$ (299)	$ (306)	$ (360)	$ (167)
Total 1,2,3	$ (10,667)	$ (4,785)	$ (4,414)	$ (4,748)	$ (8,202)	$ (9,610)	$ (13,218)	$ (22,436)	$ (23,230)	$ (23,756)	$ (24,012)	$ (20,983)

Thruput Therms

SC1 therms	12,354,645	5,862,619	4,531,935	6,981,623	18,802,390	34,350,020	55,855,789	74,163,788	72,959,702	64,465,965	47,371,380	25,011,226
SC2 therms	3,332,938	2,303,122	1,644,553	2,473,756	5,474,842	8,888,693	15,073,044	20,493,603	20,452,428	18,365,514	13,873,880	6,214,377
SC3 therms	256,642	233,643	263,267	272,195	306,003	348,640	403,888	445,344	454,895	429,227	481,880	325,552

(Refund)/Surcharge Rate per therm

SC1	$ (0.0006)	$ (0.0005)	$ (0.0006)	$ (0.0004)	$ (0.0003)	$ (0.0002)	$ (0.0002)	$ (0.0002)	$ (0.0002)	$ (0.0003)	$ (0.0004)	$ (0.0006)
SC2	$ (0.0009)	$ (0.0007)	$ (0.0010)	$ (0.0007)	$ (0.0004)	$ (0.0002)	$ (0.0002)	$ (0.0002)	$ (0.0003)	$ (0.0003)	$ (0.0004)	$ (0.0009)
SC3	$ (0.0005)	$ (0.0003)	$ (0.0007)	$ (0.0007)	$ (0.0009)	$ (0.0004)	$ (0.0004)	$ (0.0006)	$ (0.0007)	$ (0.0007)	$ (0.0007)	$ (0.0005)

Note: There is zero LPC revenue assumed in base rates for SC 12 and SC13. Further, there are no SC13 customers at this time and no history on SC12 of LPC revenue-so they have been excluded from the mechanism

Gas Contingency Reserve (GCR)
CC Calculated monthly, using an annual rate, using MJP 11.12% rate beginning Jan 2005 (for both GCR and Pipeline E-36)

	Beginning Balance	Monthly Activity	Interest Rate	Offset	Interest	Ending Balance
Nov-1999	$ (40,000,000)	$ (147,882)	0.85667%	$ 33,334,000	$ (57,739)	$ (40,205,621)
Dec-1999	$ (40,205,621)	$ (230,149)	0.85667%	$ 33,334,000	$ (59,853)	$ (40,495,623)
Jan-2000	$ (40,495,623)	$ (185,306)	0.85667%	$ 33,334,000	$ (62,145)	$ (40,743,073)
Feb-2000	$ (40,743,073)	$ (187,095)	0.85667%	$ 33,334,000	$ (64,272)	$ (40,994,441)
Mar-2000	$ (40,994,441)	$ (188,302)	0.85667%	$ 33,334,000	$ (66,431)	$ (41,249,174)
Apr-2000	$ (41,249,174)	$ (187,809)	0.85667%	$ 33,334,000	$ (68,611)	$ (41,505,594)
May-2000	$ (41,505,594)	$ (188,616)	0.85667%	$ 33,334,000	$ (70,811)	$ (41,765,021)
Jun-2000	$ (41,765,021)	$ (189,361)	0.85667%	$ 33,334,000	$ (73,037)	$ (42,027,419)
Jul-2000	$ (42,027,419)	$ (190,294)	0.85667%	$ 33,334,000	$ (75,289)	$ (42,293,002)
Aug-2000	$ (42,293,002)	$ -	0.85667%	$ 33,334,000	$ (76,749)	$ (42,369,751)
Sep-2000	$ (42,369,751)	$ (119)	0.85667%	$ 33,334,000	$ (77,407)	$ (42,447,276)
Oct-2000	$ (42,447,276)	$ 456,440	0.85667%	$ 33,334,000	$ (76,115)	$ (42,066,951)
Nov-2000	$ (42,066,951)	$ 90,301	0.86667%	$ 20,000,000	$ (190,856)	$ (42,167,506)
Dec-2000	$ (42,167,506)	$ (816,101)	0.86667%	$ 20,000,000	$ (195,655)	$ (43,179,262)
Jan-2001	$ (43,179,262)	$ 219,471	0.86667%	$ 20,000,000	$ (199,936)	$ (43,159,727)
Feb-2001	$ (43,159,727)	$ 295,986	0.86667%	$ 20,000,000	$ (199,435)	$ (43,063,176)
Mar-2001	$ (43,063,176)	$ 1,000,049	0.86667%	$ 20,000,000	$ (195,547)	$ (42,258,674)
Apr-2001	$ (42,258,674)	$ 2,126,125	0.86667%	$ 20,000,000	$ (183,695)	$ (40,316,245)
May-2001	$ (40,316,245)	$ 1,163,842	0.86667%	$ 20,000,000	$ (171,031)	$ (39,323,433)
Jun-2001	$ (39,323,433)	$ 1,175,845	0.86667%	$ 20,000,000	$ (162,374)	$ (38,309,962)
Jul-2001	$ (38,309,962)	$ 820,900	0.86667%	$ 20,000,000	$ (155,129)	$ (37,644,191)
Aug-2001	$ (37,644,191)	$ 519,632	0.86667%	$ 20,000,000	$ (150,665)	$ (37,275,224)
Sep-2001	$ (37,275,224)	$ 330,657	0.86667%	$ 20,000,000	$ (148,286)	$ (37,092,853)
Oct-2001	$ (37,092,853)	$ 188,478	0.86667%	$ 20,000,000	$ (147,321)	$ (37,051,696)
Nov-2001	$ (37,051,696)	$ 341,091	0.86083%	$ 6,667,000	$ (260,093)	$ (36,970,698)
Dec-2001	$ (36,970,698)	$ 1,048,294	0.86083%	$ 6,667,000	$ (256,352)	$ (36,178,757)
Jan-2002	$ (36,178,757)	$ 261,490	0.86083%	$ 6,667,000	$ (252,922)	$ (36,170,188)
Feb-2002	$ (36,170,188)	$ 226,437	0.86083%	$ 6,667,000	$ (252,999)	$ (36,196,750)
Mar-2002	$ (36,196,750)	$ 218,950	0.86083%	$ 6,667,000	$ (253,260)	$ (36,231,060)
Apr-2002	$ (36,231,060)	$ 174,428	0.86083%	$ 6,667,000	$ (253,747)	$ (36,310,378)
May-2002	$ (36,310,378)	$ 106,576	0.86083%	$ 6,667,000	$ (254,721)	$ (36,458,523)
Jun-2002	$ (36,458,523)	$ 73,947	0.86083%	$ 6,667,000	$ (256,137)	$ (36,640,713)
Jul-2002	$ (36,640,713)	$ 24,877	0.86083%	$ 6,667,000	$ (257,917)	$ (36,873,752)
Aug-2002	$ (36,873,752)	$ 135,905	0.86083%	$ 6,667,000	$ (259,445)	$ (36,997,292)
Sep-2002	$ (36,997,292)	$ 182,196	0.86083%	$ 6,667,000	$ (260,309)	$ (37,075,405)
Oct-2002	$ (37,075,405)	$ 605,359	0.86083%	$ 6,667,000	$ (259,160)	$ (36,729,207)
Nov-2002	$ (36,729,207)	$ 218,262	0.86083%	$ -	$ (315,238)	$ (36,826,183)
Dec-2002	$ (36,826,183)	$ 498,519	0.86083%	$ -	$ (314,866)	$ (36,642,530)
Jan-2003	$ (36,642,530)	$ 351,066	0.86083%	$ -	$ (313,920)	$ (36,605,384)
Feb-2003	$ (36,605,384)	$ 364,443	0.86083%	$ -	$ (313,543)	$ (36,554,483)
Mar-2003	$ (36,554,483)	$ 400,258	0.86083%	$ -	$ (312,950)	$ (36,467,175)
Apr-2003	$ (36,467,175)	$ 178,472	0.86083%	$ -	$ (313,153)	$ (36,601,857)
May-2003	$ (36,601,857)	$ 142,664	0.86083%	$ -	$ (314,467)	$ (36,773,660)
Jun-2003	$ (36,773,660)	$ 78,899	0.86083%	$ -	$ (316,220)	$ (37,010,981)
Jul-2003	$ (37,010,981)	$ 14,171	0.86083%	$ -	$ (318,542)	$ (37,315,352)
Aug-2003	$ (37,315,352)	$ 42,257	0.86083%	$ -	$ (321,041)	$ (37,594,136)
Sep-2003	$ (37,594,136)	$ 161,037	0.86083%	$ -	$ (322,930)	$ (37,756,029)
Oct-2003	$ (37,756,029)	$ 1,054,685	0.86083%	$ -	$ (320,477)	$ (37,021,821)
Nov-2003	$ (37,021,821)	$ 427,585	0.86083%	$ -	$ (316,856)	$ (36,911,091)
Dec-2003	$ (36,911,091)	$ 493,789	0.86083%	$ -	$ (315,618)	$ (36,732,920)
Jan-2004	$ (36,732,920)	$ 508,603	0.86083%	$ -	$ (314,020)	$ (36,538,337)
Feb-2004	$ (36,538,337)	$ 633,223	0.86083%	$ -	$ (311,809)	$ (36,216,922)
Mar-2004	$ (36,216,922)	$ 517,040	0.86083%	$ -	$ (309,542)	$ (36,009,424)
Apr-2004	$ (36,009,424)	$ 333,448	0.86083%	$ -	$ (308,546)	$ (35,984,521)
May-2004	$ (35,984,521)	$ 292,175	0.86083%	$ -	$ (308,509)	$ (36,000,855)
Jun-2004	$ (36,000,855)	$ 231,182	0.86083%	$ -	$ (308,912)	$ (36,078,586)
Jul-2004	$ (36,078,586)	$ 176,851	0.86083%	$ -	$ (309,815)	$ (36,211,551)
Aug-2004	$ (36,211,551)	$ 214,192	0.86083%	$ -	$ (310,799)	$ (36,308,158)
Sep-2004	$ (36,308,158)	$ 217,566	0.86083%	$ -	$ (311,616)	$ (36,402,209)
Oct-2004	$ (36,402,209)	$ 210,949	0.86083%	$ -	$ (312,454)	$ (36,503,714)
Nov-2004	$ (36,503,714)	$ 318,366	0.86083%	$ -	$ (312,866)	$ (36,498,214)
Dec-2004	$ (36,498,214)	$ 433,578	0.86083%	$ -	$ (312,323)	$ (36,376,959)
Jan-2005	$ (36,376,959)	$ 474,119	0.92667%	$ -	$ (334,896)	$ (36,237,737)
Feb-2005	$ (36,237,737)	$ 554,651	0.92667%	$ -	$ (333,233)	$ (36,016,319)
Mar-2005	$ (36,016,319)	$ 562,992	0.92667%	$ -	$ (331,143)	$ (35,784,469)
Apr-2005	$ (35,784,469)	$ 311,009	0.92667%	$ -	$ (330,162)	$ (35,803,622)
May-2005	$ (35,803,622)	$ 302,085	0.92667%	$ -	$ (330,381)	$ (35,831,917)
Jun-2005	$ (35,831,917)	$ 273,415	0.92667%	$ -	$ (330,776)	$ (35,889,278)

Gas Contingency Reserve (GCR)
CC Calculated monthly, using an annual rate, using MJP 11.12% rate beginning Jan 2005 (for both GCR and Pipeline E-36)

	Beginning Balance	Monthly Activity	Interest Rate	Offset	Interest	Ending Balance
Jul-2005	$ (35,889,278)	$ 157,087	0.92667%	$ -	$ (331,846)	$ (36,064,037)
Aug-2005	$ (36,064,037)	$ 259,646	0.92667%	$ -	$ (332,990)	$ (36,137,381)
Sep-2005	$ (36,137,381)	$ 225,278	0.92667%	$ -	$ (333,829)	$ (36,245,932)
Oct-2005	$ (36,245,932)	$ 202,575	0.92667%	$ -	$ (334,940)	$ (36,378,298)
Nov-2005	$ (36,378,298)	$ 292,555	0.92667%	$ -	$ (335,750)	$ (36,421,493)
Dec-2005	$ (36,421,493)	$ 425,092	0.92667%	$ -	$ (335,536)	$ (36,331,937)
Jan-2006	$ (36,331,937)	$ 1,609,056	0.92667%	$ -	$ (329,221)	$ (35,052,102)
Feb-2006	$ (35,052,102)	$ 413,907	0.92667%	$ -	$ (322,898)	$ (34,961,094)
Mar-2006	$ (34,961,094)	$ 500,396	0.92667%	$ -	$ (321,654)	$ (34,782,352)
Apr-2006	$ (34,782,352)	$ 1,016,600	0.92667%	$ -	$ (317,606)	$ (34,083,358)
May-2006	$ (34,083,358)	$ 294,626	0.92667%	$ -	$ (314,474)	$ (34,103,206)
Jun-2006	$ (34,103,206)	$ 261,046	0.92667%	$ -	$ (314,814)	$ (34,156,974)
Jul-2006	$ (34,156,974)	$ 890,117	0.92667%	$ -	$ (312,397)	$ (33,579,254)
Aug-2006	$ (33,579,254)	$ 245,158	0.92667%	$ -	$ (310,032)	$ (33,644,128)
Sep-2006	$ (33,644,128)	$ 247,442	0.92667%	$ -	$ (310,622)	$ (33,707,308)
Oct-2006	$ (33,707,308)	$ 838,563	0.92667%	$ -	$ (308,469)	$ (33,177,215)
Nov-2006	$ (33,177,215)	$ 289,351	0.92667%	$ -	$ (306,102)	$ (33,193,965)
Dec-2006	$ (33,193,965)	$ 271,600	0.92667%	$ -	$ (306,339)	$ (33,228,704)
Jan-2007	$ (33,228,704)	$ 1,000,339	0.92667%	$ -	$ (303,284)	$ (32,531,649)
Feb-2007	$ (32,531,649)	$ 406,402	0.92667%	$ -	$ (299,577)	$ (32,424,824)
Mar-2007	$ (32,424,824)	$ 467,917	0.92667%	$ -	$ (298,302)	$ (32,255,209)
Apr-2007	$ (32,255,209)	$ 968,332	0.92667%	$ -	$ (294,412)	$ (31,581,288)
May-2007	$ (31,581,288)	$ 265,847	0.92667%	$ -	$ (291,422)	$ (31,606,862)
Jun-2007	$ (31,606,862)	$ 220,536	0.92667%	$ -	$ (291,868)	$ (31,678,195)
Jul-2007	$ (31,678,195)	$ 855,417	0.92667%	$ -	$ (289,588)	$ (31,112,365)
Aug-2007	$ (31,112,365)	$ 216,324	0.92667%	$ -	$ (287,306)	$ (31,183,347)
Sep-2007	$ (31,183,347)	$ 418,076	0.92667%	$ -	$ (287,029)	$ (31,052,300)
Oct-2007	$ (31,052,300)	$ 202,525	0.92667%	$ -	$ (286,813)	$ (31,136,588)
Nov-2007	$ (31,136,588)	$ 1,479,167	0.92667%	$ -	$ (281,679)	$ (29,939,100)
Dec-2007	$ (29,939,100)	$ (245,810)	0.92667%	$ -	$ (278,575)	$ (30,463,485)
Jan-2008	$ (30,463,485)	$ 1,625,167	0.92667%	$ -	$ (274,765)	$ (29,113,083)
Feb-2008	$ (29,113,083)	$ 368,796	0.92667%	$ -	$ (268,072)	$ (29,012,359)
Mar-2008	$ (29,012,359)	$ 408,423	0.92667%	$ -	$ (266,956)	$ (28,870,892)
Apr-2008	$ (28,870,892)	$ 293,028	0.92667%	$ -	$ (266,179)	$ (28,844,043)
May-2008	$ (28,844,043)	$ 1,456,263	0.92667%	$ -	$ (260,541)	$ (27,648,321)
Jun-2008	$ (27,648,321)	$ 198,692	0.92667%	$ -	$ (255,287)	$ (27,704,916)
Jul-2008	$ (27,704,916)	$ 183,130	0.92667%	$ -	$ (255,884)	$ (27,777,670)
Aug-2008	$ (27,777,670)	$ 1,432,074	0.92667%	$ -	$ (250,771)	$ (26,596,367)
Sep-2008	$ (26,596,367)	$ 175,436	0.92667%	$ -	$ (245,647)	$ (26,666,578)
Oct-2008	$ (26,666,578)	$ 185,566	0.92667%	$ -	$ (246,251)	$ (26,727,263)
Nov-2008	$ (26,727,263)	$ 239,499	0.92667%	$ -	$ (246,563)	$ (26,734,327)
Dec-2008	$ (26,734,327)	$ 574,150	0.92667%	$ -	$ (245,078)	$ (26,405,256)
Jan-2009	$ (26,405,256)	$ 252,086	0.92667%	$ -	$ (243,521)	$ (26,396,691)
Feb-2009	$ (26,396,691)	$ 252,086	0.92667%	$ -	$ (243,441)	$ (26,388,046)
Mar-2009	$ (26,388,046)	$ 252,086	0.92667%	$ -	$ (243,361)	$ (26,379,322)
Apr-2009	$ (26,379,322)	$ (414,581)	0.92667%	$ -	$ (246,369)	**$ (27,040,273)**
		$ 42,444,860			$ (29,485,133)	

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
PSC Case No. 08-G-0609

Total Forecast Gas Delivery Revenue by month
(before Revenue Requirement)

		# days	Gas Delivery Revenue (Whole $)	%
4/1/2009	April	30	$27,224,254	9.69%
5/1/2009	May	31	$22,395,335	7.97%
6/1/2009	June	30	$17,624,428	6.27%
7/1/2009	July	31	$14,487,237	5.16%
8/1/2009	August	31	$13,768,719	4.90%
9/1/2009	September	30	$15,115,873	5.38%
10/1/2009	October	31	$20,042,217	7.13%
11/1/2009	November	30	$24,745,651	8.81%
12/1/2009	December	31	$29,355,312	10.45%
1/1/2010	January	31	$32,520,381	11.57%
2/1/2010	February	28	$32,483,194	11.56%
3/1/2010	March	31	$31,219,207	11.11%
		365	$280,981,809	100.00%

JP Section 6.11
Illustration of Gas Operations Capital Expenditure Report
(note: some modification of format is possible)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Gas Business Unit Capital Expenditures
Historical Year Ended December 2007 and Estimated For Years 2008-2013

		Actual	Forecast
Gas Operations		Fiscal Year Ending March 31, 2010	Fiscal Year Ending March 31, 2011
Budget Number	**Budget Description**		
Growth			
CNx055-058	New Meter Labor	$ 1,945,207	$ 1,425,883
CN3663	Meter Purchases -Growth	1,447,999	1,969,066
CNx045,046	Franchise New Main	13,617	
CNx047,048	Franchise New Services		
CNx051,052	Franchise New Services		
CNx050,049	New Main	8,020,179	6,456,202
CNx053,54	New Services	14,334,472	10,730,643
	Growth total	$ 25,761,475	$ 20,581,794
Mandated			
CNx041,42,43,44	Meters - PT's	$ 1,458,789	1,642,350
CN3663	Meter Purchases - Non-growth		$ 2,482,164
CNx060,59	Government	6,036,642	7,674,534
CNx064	Cast Iron Encroachment	958,849	1,446,101
CNx030,31	Exposures	294,245	109,636
CNx032	Third Party Damage	93,843	37,276
CNx034,33	Main Renewals	9,754,339	23,133,238
CNx040,38	Bare Steel HP Inside Sets		6,358,900
CNx040,39	Service Renewals	7,455,282	9,561,702
	Mandated total	$ 26,051,988	$ 52,445,902
Reliability			
CNx038,37	Regulator Station	$ 2,973,582	$ 3,289,086
CNx036	System reinforcement	65,475	548,181
C00602-604	SCADA	39,244	186,382
	Andrews Rd GR Station (in-service 7/09)		-
	New Pipeline to Malta to support growth (in-service 4/09)		-
	GEMS Upgrade	1,401,452	-
	Reliability total	$ 4,479,753	$ 4,023,649
Discretionary			
CNx062	Tools	$ 367,413	$ 650,000
	Discretionary total	$ 367,413	$ 650,000
	Gas Operations total	$ 56,660,629	$ 77,701,345
Other Gas Capital Allocations			
Facilities - Other			$ 1,380,000
Facilities - Saratoga Service Center (in-service 4/09)			
Facilities - Syracuse Office Complex (in-services 3 month lag)			
Customer Service (non-AMR)			255,000
Information Services			165,000
	Other Gas Capital Allocations total	$ -	$ 1,800,000
Total Gas Operations and Other Gas Allocations		$ 56,660,629	$ 79,501,345
Total Common		$ 377,737,524	$ 530,008,963