Date of Request: February 4, 2010 Request No. AAE-3
Due Date: March 15, 2010

NMPC Req. No. NM 3 DPS-3

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Allison Esposito

TO: Revenue Requirements Panel

Request:

1. Please provide, in Excel, a list of all work orders over $10,000 entered into the system from 1/1/03 – 12/31/09 that had periods of inactivity of over 6 months. For each work order please provide the following information:
   a. Work order number
   b. A description of the work order
   c. The date the work order was created
   d. The date the work order was operationally placed in service
   e. The date the inactivity began
   f. The date the inactivity ended
   g. The total amount closed to Plant in Service
   h. The applicable depreciation rate
   i. The amount of AFUDC, if any, which accrued during inactivity and closed to plant in service
2. Based on this information, please provide an analysis showing the amount of depreciation related to inactive work orders which should have been expensed from 1/1/03 – 12/31/09. Please provide all supporting workpapers and calculations. To the extent that the Company is unable to quantify a precise amount, please provide the best estimate, along with all supporting workpapers, calculations and assumptions used.

Please note, if this Information Request is too voluminous or time consuming, please call Allison Esposito to work out something regarding the data that is acceptable to both the Company and Staff.

Response:

1. Please see Attachment 1, DPS-3 -AAE-3 ("the Attachment"). As per our discussion with Allison Esposito on 2/9/2010, the Company agreed to provide data for work orders over $10,000 that were initiated during the five calendar years 2005 – 2009, which should be representative of prior periods. It was further agreed to that the Company would provide one report as of 12/31/09, with data for all work orders initiated during those five years. As to the specific

information being requested, the Company is providing items A – D as requested above. For purposes of estimating the periods of any potential inactivity that may have occurred after the in-service date (items E and F), the Company is providing the date the work order was last charged and the first Continuing Property Record (CPR) month, which represents when the work order was first closed to Completed Construction Not Classified (CCNC) - FERC account 106. For the purposes of item G, the Company is providing the dollars included in either CCNC - FERC account 106 or Plant In Service (PIS) - FERC account 101, which are separately identified on the attachment. Consistent with the Company's filing, the Company is providing the appropriate depreciation composite rate based on the work order type for item H. For purposes of AFUDC - item I, the Company is only able to provide the total AFUDC associated with each work order as opposed to the AFUDC accrued during any specific period of inactivity. However, any accrual of AFUDC beyond the in-service date is automatically trued-up in the fixed asset system as of the in-service date.

2. The Company's position is that the depreciation expense booked during the period in question is accurate based on the first CPR month date. The Company considers that its calculation of depreciation expense is appropriate given the company's procedure of following broad group depreciation. This procedure is often followed by Electric utilities due to the significant volume of assets processed. Service lives tend to be more predictable as a group, rather than an expectation attached to a particular unit and statistical ratios are used as a result. Depreciation studies calculate an average prospective life for the assets, and this was updated and submitted in the depreciation study recently prepared by Ron White. Included in the study is a comparison of the book reserve and a calculated reserve based on the results of the study (Exhibit REW-2, page 13). The comparison of electric and common depreciation reserve results in a reserve excess of approximately 2% of the book reserve. Therefore, the Company believes that the book depreciation reserve is accurately stated.

   During the course of the construction work order lifecycle there are compelling business reasons why periods of apparent inactivity occur. In order to facilitate effective work management practices and to provide for a ready supply of schedulable work orders, the Company initiates work orders in advance of their schedule for release to field operations. This is referred to as the "Get Ahead Program." Also during the work order lifecycle, there may be work orders that are waiting on materials, work orders that are waiting for developer, delays in pursuing and procuring easements, delays in inspections or DOT and/or customers completing their work. Work may also be on hold waiting for a required outage, pending changes in regulations, pending a payment dispute, or due to coordination of work with an electricity generator.

   At the end of its life cycle, a significant amount of information is required to complete the transfer from Construction Work in Progress (CWIP) to CCNC. The information required includes, among other things, the in-service date as advised by the Project Engineer, Project Manager or other Responsible Party for the work order (either manually provided or sent automatically through the Work Management System (WMS) based on work order requirements being completed) and a preliminary estimate of the assets constructed that is used until all late/lagging charges have been received (refer comment below) and as built drawings are finalized. Typically, for smaller work orders this information is provided in the same month the work is in service or automatically through WMS system interfaces, which facilitates an accelerated closing process. However, there are typically timing lags for closing larger work orders because of the work involved in developing preliminary estimates of the data required to close the order. Additionally, it is normal business practice to incur trailing charges on work orders subsequent to the in-service date that may relate to completing minor components of the job and for invoice processing. The Company has implemented new Fixed Asset and WMS systems in recent years that have improved the closing process and is making on-going efforts to close work orders in a timely fashion. The majority of work orders are closed in a timely manner (considered within a few months of the in-service date).

While the Company considers that its calculation of depreciation expense is appropriate given the nature and scale of this activity it has nevertheless made a high level calculation of depreciation for the period between the in-service date of a work order and either the first CPR month of work orders closed to CCNC/PIS or up to the 12/31/2009 date of the report for work orders in CWIP. The Company used the in-service date as the starting point for this calculation. However, given the nature and scale of this activity and the time that is typically required to complete the activities needed to complete the transfer to CCNC (of particularly the larger projects) no calculation has been made in respect of work orders where this transfer occurred within six months of the in-service date. Additionally due to the voluminous amount of data, the Company applied a high-level approach to develop the depreciation calculation by using total dollars with no consideration to the timing of the charges. Although this approach facilitates a high-level calculation, it is flawed because trailing charges incurred subsequent to the in-service date are being including in the total dollars in the calculation as if they had been incurred prior to the in-service date. Please see column N of the Attachment for the depreciation estimate requested.

<u>Name of Respondent:</u>
Lisa Figliozzi

<u>Date of Reply:</u>
March 15, 2010

Date of Request: February 5, 2010
Due Date: February 15, 2010

Request No. DPS-13(RAV-9)
NMPC Req. No. NM 13

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO:

Request:

A. Please provide a copy of all monthly, quarterly, semi-annual and annual reports provided to top National Grid - US management on the status of achieving the KeySpan merger savings from January 1, 2008 to present. This should include, but is not limited to, copies of all quarterly reports provided to CEO Holiday on actually achieved versus internal management targeted KeySpan related synergy and efficiency savings.
B. Same as A. for all reports provided to National Grid – UK management.
C. Continue providing monthly updates of the information requested in A. and B. above until further notice.

Response:

A. Reporting of integration savings (synergy savings plus efficiency savings) following the Keyspan acquisition takes place on a quarterly basis. Reports are provided to the Group Executive via US Shared Services Finance.

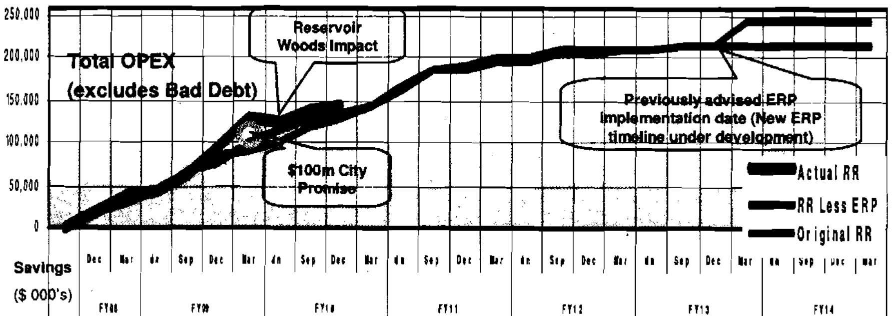
All Executive Summary reports which have been produced are attached. They are as follows and include the savings resulting from targeted synergy and efficiency savings;

Synergy Savings Tracking to 31st December 2009. (1 Sheet)
Synergy Savings Tracking to 30th September 2009. (1 Sheet)
Synergy Savings Tracking to 30th June 2009. (1 Sheet)
Synergy Savings Tracking to 31st March 2009. (1 Sheet)
Synergy Savings Tracking to 31st December 2008. (2 Sheets)
Synergy Savings Tracking to 30th September 2008. (2 Sheets)
Synergy Savings Tracking to 30th June 2008. (2 Sheets)
Synergy Savings Tracking to 31st March 2008. (2 Sheets)
Synergy Savings Tracking to 31st December 2007. (1 Sheet)

Synergy Savings Tracking to 31st December 2009:

Run Rate exceeds target but is slowing and projected to be just ahead of year end target.

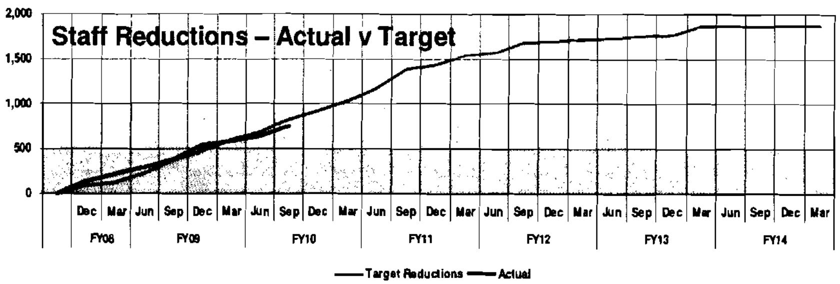
OPEX Reductions $ in Millions	Q3 FY10 Act	Q3 FY10 Target	Q3 FY10 Var	RR Dec 09 Act	RR Dec 09 Target	RR Dec 09 Var	F'Cast RR Mar 10 F'cast	F'Cast RR Mar 10 Target	F'Cast RR Mar 10 Var	Day N Target
OPEX	106.0	93.5	12.4	150.3	133.4	16.9	156.7	144.1	12.6	229.6
Total Property	(2.6)	2.6	(5.3)	(4.6)	4.0	(8.6)	(4.6)	4.1	(8.7)	17.3
Total OPEX	103.3	96.2	7.2	145.7	137.4	8.3	152.1	148.2	3.9	246.9
Bad Debt & Weather Hedge	35.6	16.9	18.7	47.8	22.5	25.3	47.8	24.0	23.8	40.7
Grand Total	138.9	113.1	25.8	193.5	160.0	33.6	199.8	172.2	27.6	287.6

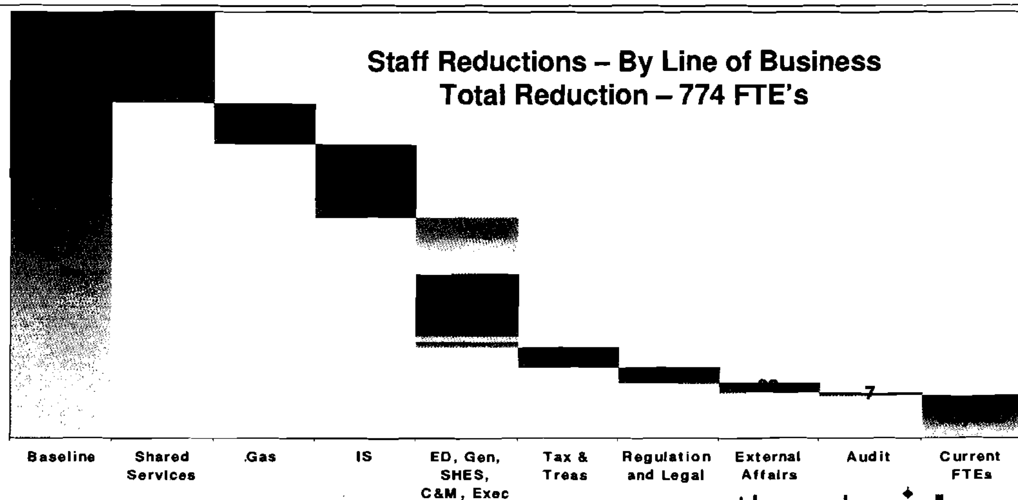


March 09 City Promise: $100M / £67M run rate exceeded - $200M final target to be achieved

- December 09 run rate is ahead of the savings target by around $8 million.
- Reservoir Woods costs, a negative synergy of $11.5 million was recognized on 1st May 2009. Weak real estate demand is restricting offset of this cost, by reducing the property footprint.
- Transformation projects and the reorganization of lines of business are creating challenges in relating savings back to the original Mercer Initiatives.
- Many of the obvious savings initiatives have been achieved. However key integration projects such as Call Centre rationalization, reduction of the Property Footprint, Systems Integration and Gas AMR have either been delayed or cancelled leading to a slowing down of the increase in the level of savings.
- The main contributors to savings over the quarter were EDO, through the transformation project, and Customer and Markets. Workforce Management within Customer and Markets regarding call centre scheduling and better utilization of resources to meet customer requirements generated significant savings over the quarter.
- SHE's, Corporate Affairs, Generation & Group Audit have all completed their integration initiatives.

- 774 employee positions eliminated as of 31st December 2009; falling below target (FY10 Q3 target is 990). (Figures exclude contractors.)
- The cancelled Gas AMR and lack of a single customer system has caused the FTE savings gap to widen over the quarter and is projected to continue to do so by year end.





Electric Distribution 81.7, Generation 11, SHE's 32.5, C&M 125, Exec 15

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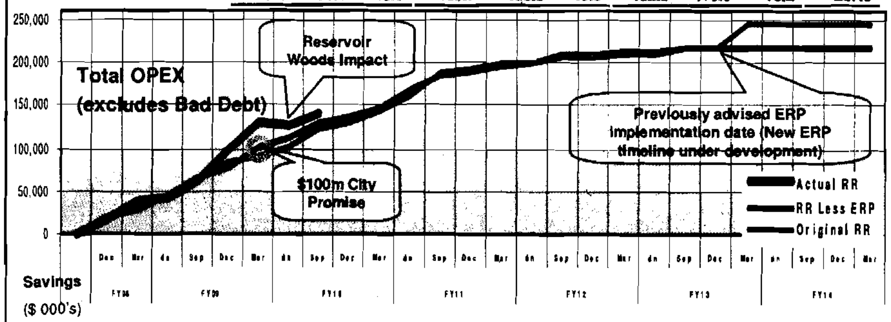
Synergy Savings Tracking to 30th September 2009:

Run Rate exceeds target but is slowing and projected to be just ahead of year end target.

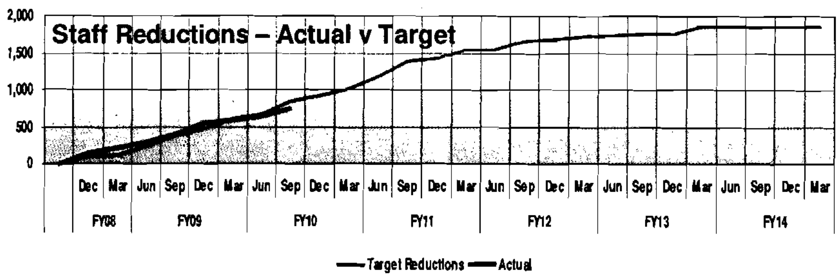
OPEX Reductions	Q2 FY10			RR Sep 09			F'Cast RR Mar 10			Day N
$ in Millions	Act	Target	Var	Act	Target	Var	F'cast	Target	Var	Target
OPEX	66.6	60.2	6.4	145.4	128.9	16.5	159.1	146.7	12.4	229.6
Total Property	(1.5)	1.6	(3.2)	(4.8)	3.4	(8.2)	(4.8)	4.1	(9.0)	17.3
Total OPEX	65.0	61.8	3.2	140.5	132.3	8.3	154.2	150.8	3.4	246.9
Bad Debt & Weather Hedge	20.3	9.7	10.7	28.2	21.5	6.7	38.6	25.8	12.8	40.7
Grand Total	85.4	71.4	13.9	168.7	153.8	15.0	192.8	176.6	16.2	287.6

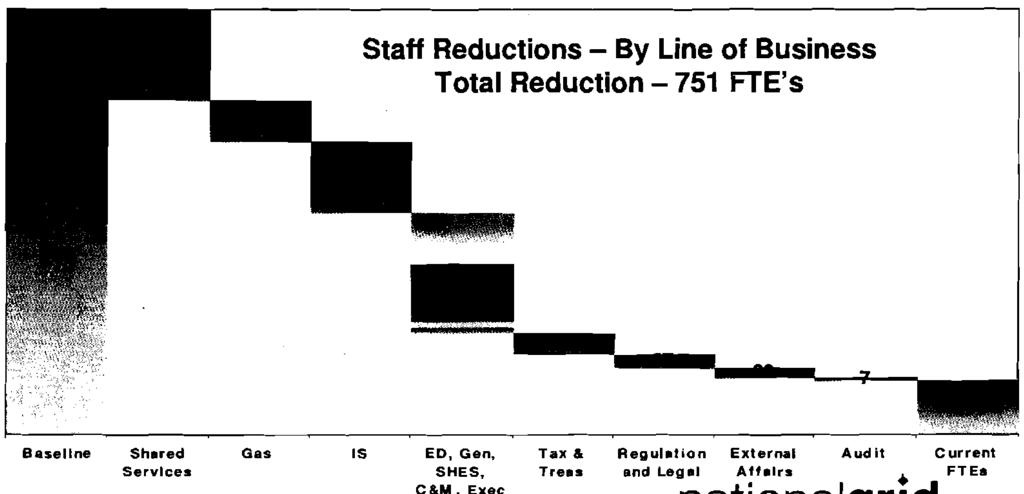


Original City Promise: $100M / £67M run rate exceeded - $200M final target to be achieved

- September 09 run rate is ahead of the savings target by around $8 million.
- Reservoir Woods costs, a negative synergy of $11.5 million was recognized on 1st May 2009. Weak real estate demand is restricting offset of this cost, by reducing the property footprint.
- Transformation projects and the reorganization of lines of business are creating challenges in relating savings back to the original Mercer Initiatives.
- Many of the obvious savings initiatives have been achieved. However some of the large savings items such as Call Centre rationalization, reduction of the Property Footprint, Systems Integration and Gas AMR have either been delayed or cancelled leading to a slowing down of the increase in the level of savings.
- Progress on the US ERP decision should provide some impetus in accelerating savings in FY11/12. Transformation and consolidation initiatives may though dilute original targets.
- The EDO transformation is also gathering pace and accounted for an additional $2.5 million of savings over the quarter. Other savings drivers are more efficient use of customer contact through e-solutions in billing and self-service.
- SHE's, Corporate Affairs, Generation & Group Audit have completed their integration initiatives.

- 751 employee positions eliminated as of 30th September 2009; falling below target (FY10 Q2 target is 830). (Figures exclude contractors.)
- The cancelled Gas AMR and lack of a single customer system has caused the FTE savings gap to widen over the quarter and is projected to continue to do so by year end.





Electric Distribution 70.9, Generation 11, SHE's 32.5, C&M 114, Exec 15

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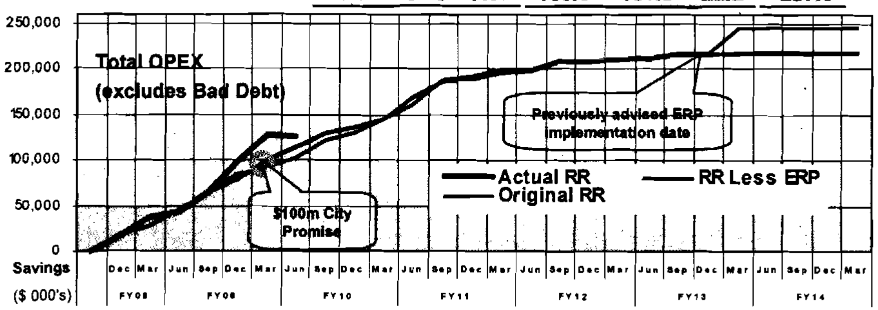
Synergy Savings Tracking to 30th June 2009:

Run Rate target exceeded but down on prior quarter / FTE's slightly below target

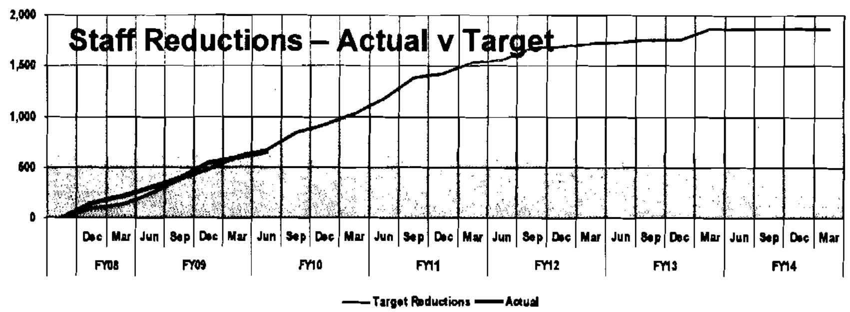
OPEX Reductions $ in Millions	Q1 FY10			RR Jun 09			Day N
	Act	Target	Var	Act	Target	Var	Target
OPEX	37.3	28.0	9.3	131.2	112.2	19.0	229.6
Total Property	(0.3)	0.8	(1.1)	(5.2)	3.1	(8.2)	17.3
Total OPEX	36.9	28.7	8.2	126.0	115.3	10.7	246.9
Bad Debt & Weather Hedge	6.4	4.0	2.4	27.6	16.2	11.4	40.7
Grand Total	43.4	32.8	10.6	153.6	131.5	22.2	287.6

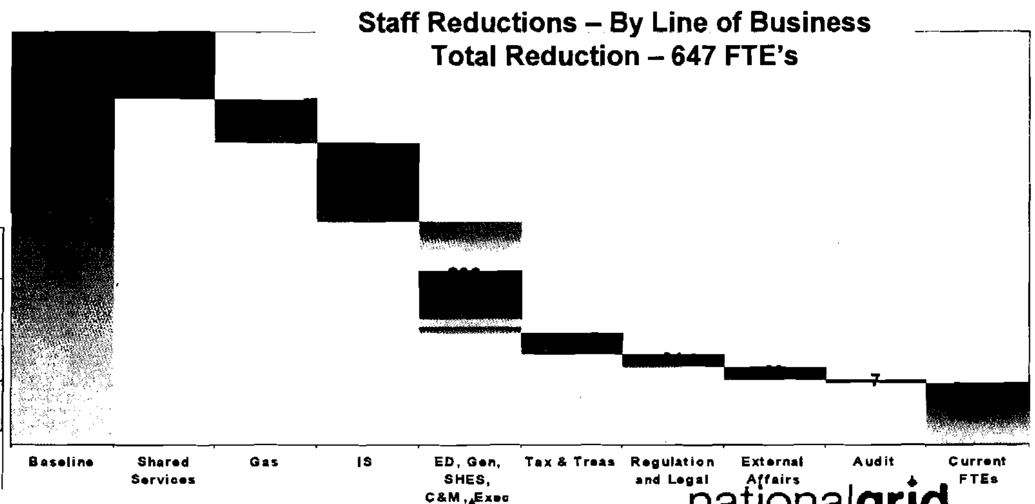


- June 09 run rate is ahead of the savings target by around $11 million.
- Reservoir Woods costs, a negative synergy of $11.5 million was recognized on 1st May 2009. Weak demand for commercial property is impacting the ability to offset this cost by reducing the property footprint.
- The ERP decision is awaited, around $30m of synergy benefits are affected by this project. In addition organizational changes and strategic decision making are creating challenges to achieve targeted savings.
- Agent Desktop is expected to enable customer and market synergies which were previously affected by ERP implementation. This should provide a fresh impetus and benefits to begin towards the end of Q3 FY10.
- SHE's, Corporate Affairs, Generation and Group Audit have completed their integration initiatives.

Original City Promise: $100M / £67M run rate exceeded - $200M final target to be achieved

- 647 employee positions eliminated as of 30th June 2009; Slightly below target. (Figures exclude contractors.)
- Shared Services, Electric Distribution and IS are driving the FTE reductions. The cancelled Gas AMR project will though lead to a widening of the shortfall in outer periods.





Electric Distribution 59.5, Generation 11, SHE's 32.5, C&M 89, Exec 14

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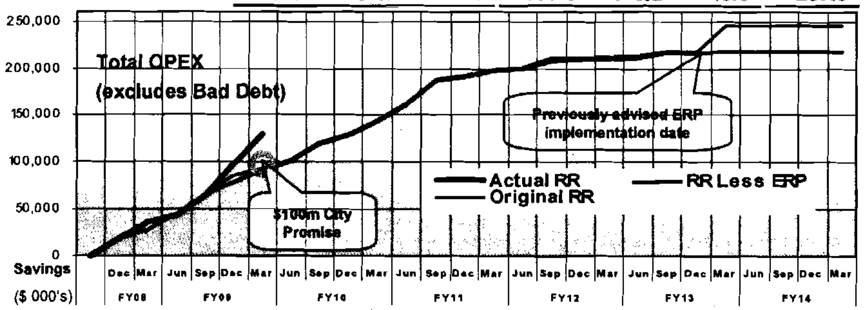
Synergy Savings Tracking to 31st March 2009:

March run rate exceeded year 1 City promise / FTE's essentially on target

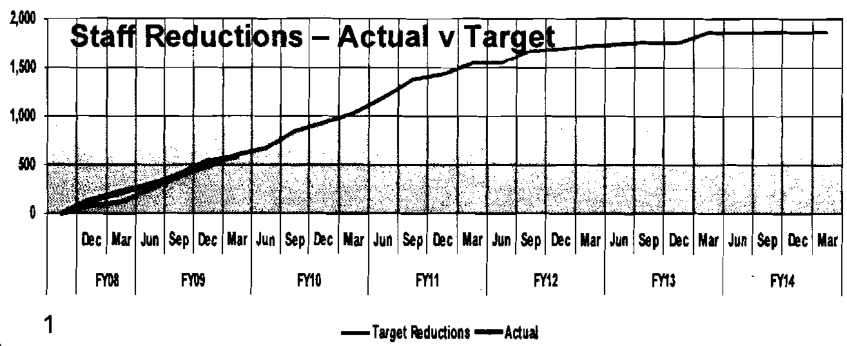
OPEX Reductions $ in Millions	Actual Savings FY09 Act	Actual Savings FY09 Target	Actual Savings FY09 Var	Run Rate March 09 Act	Run Rate March 09 Target	Run Rate March 09 Var	Day N Target
OPEX	71.6	73.4	(1.8)	124.5	97.9	26.7	230.1
Total Property	4.7	2.6	2.1	6.1	3.0	3.1	16.8
Total OPEX	76.2	76.0	0.3	130.7	100.9	29.8	246.9
Bad Debts	15.4	8.0	7.4	26.2	12.3	13.9	40.7
Grand Total	91.6	84.0	7.6	156.9	113.2	43.6	287.6



City Promise: $100M / £67M run rate target at the end of the first full year

- March 09 run rate is well ahead of the $100m City promise at $130 million.
- Significant additional initiatives in Benefits, Property and Executive and locational labor rate differentials in Customer and Markets are driving the favorability.
- A decision regarding the consolidation of the US ERP platforms is expected in June 09. Around $30m of synergy benefits are affected by this project.
- The cost of outside professional services have restricted synergies within Legal and Regulation. External professionals have compensated for a reduction of staff in Legal and increased work within Regulation.
- Recognition of Reservoir Woods costs (a negative synergy) will be recognized on the expected lease commencement date in June 2009.

- 586 employee positions eliminated as of 31st March 2009; Essentially on target. (Figures exclude contractors.)
- Shared Services, Electric Distribution and IS are driving the FTE reductions. The Gas AMR project and revision of initiatives in Customer and Markets have led to some re-phasing.



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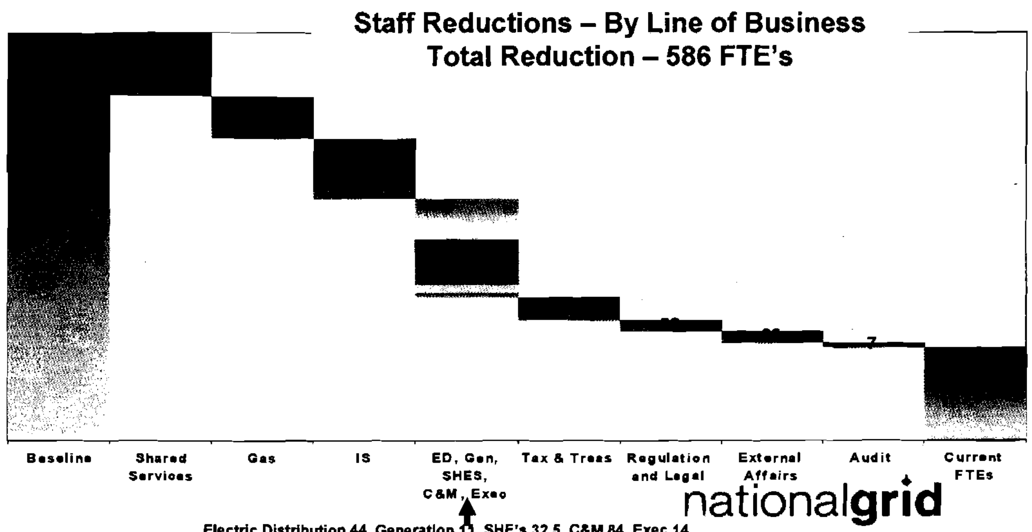

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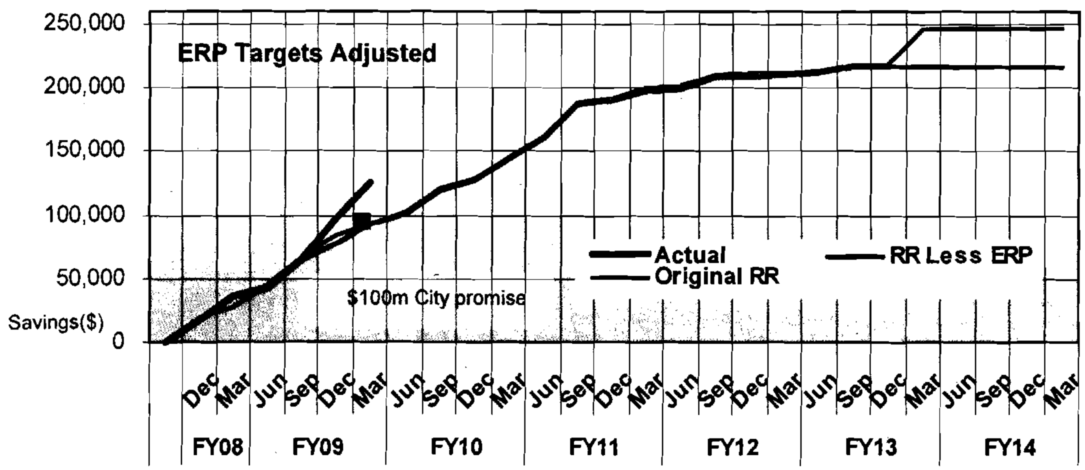
Synergy Savings Tracking to 31st December 2008: March run rate likely to exceed Year 1 City forecast

OPEX Reductions $ in Millions	Fiscal Year Basis 08/09 Q1, Q2 & Q3 Act	Target	Var	Run Rate Basis As at Dec 08 Act	Target	Var	Run Rate Basis As at Mar 09 F'cast	Target	Var	Day N Target
Shared Services (less Property)	8.7	2.9	5.7	24.4	5.1	19.3	28.7	5.3	23.4	35.1
Gas Distribution	5.8	10.8	(5.0)	12.5	18.6	(6.1)	16.6	23.2	(6.6)	47.9
Information Services	4.0	4.7	(0.7)	6.6	8.9	(2.3)	9.3	9.2	0.1	41.0
Customers and Markets	7.3	6.6	0.7	10.1	11.0	(0.9)	15.6	12.0	3.6	37.8
Electric Distribution	1.6	4.3	(2.6)	5.7	5.5	0.3	11.6	5.7	5.9	20.1
Tax, Treas. & Decision Support	5.0	3.5	1.5	8.0	6.1	1.9	8.2	7.0	1.2	15.4
Regulation and Legal	4.5	4.3	0.2	6.0	7.6	(1.7)	6.6	8.6	(2.0)	12.0
Executive	4.9	5.5	(0.5)	6.6	7.8	(1.3)	11.1	7.8	3.3	7.8
SHES	2.7	1.1	1.6	4.0	3.9	0.1	4.5	4.0	0.5	5.0
External Affairs	3.6	3.3	0.3	4.8	4.7	0.2	4.8	4.7	0.2	4.8
Generation	1.0	0.9	0.1	1.7	1.3	0.4	1.7	1.3	0.4	1.7
Group Audit	1.1	0.7	0.4	1.4	0.9	0.5	1.4	0.9	0.5	1.2
OPEX	**50.3**	**48.7**	**1.6**	**91.7**	**81.3**	**10.4**	**120.2**	**89.7**	**30.5**	**229.6**
Other Property Synergies	1.8	1.6	0.2	2.4	2.7	(0.3)	2.8	2.9	(0.1)	13.4
Metrotech Savings	1.3	0.2	1.1	3.5	0.3	3.2	3.5	0.3	3.2	3.9
Total Property	**3.1**	**1.8**	**1.2**	**5.9**	**3.0**	**2.9**	**6.3**	**3.2**	**3.1**	**17.3**
Total OPEX	**53.3**	**50.5**	**2.8**	**97.6**	**84.4**	**13.2**	**126.5**	**92.9**	**33.6**	**246.9**
Bad Debts	3.0	3.9	(0.9)	7.4	9.6	(2.1)	10.1	12.3	(2.2)	40.7
Grand Total	**56.3**	**54.4**	**1.9**	**105.0**	**93.9**	**11.1**	**138.6**	**105.2**	**31.4**	**287.6**



City Promise: $100M / £67M run rate target at the end of the first full year

- December 08 run rate is closing in on the $100m City promise.
- Run rate growth across the final quarter is forecast to drive the year end March 09 run rate to circa $125m (excluding bad debt synergies).
- Recognition of Reservoir Woods costs (a negative synergy) will be delayed until the expected lease commencement date in June 2009.
- Executive to exceed synergy targets by 31st March 2009 due to additional items identified and FTE' target completed.
- Additional HR savings identified include $6.5m pension assumption alignments, $6.5m ($10.2m in March 09) for the elimination of the Keyspan Long Term Incentive Plan and $4.2m for alignment of benefits.
- The removal of AMR (Gas) project and Customer System has presented significant challenges to Gas Distribution and Customer & Markets.
- $30m of synergy benefits relating to the consolidation of the US systems platform have been eliminated from target run rates in 13/14 (but remain in the Day N target)

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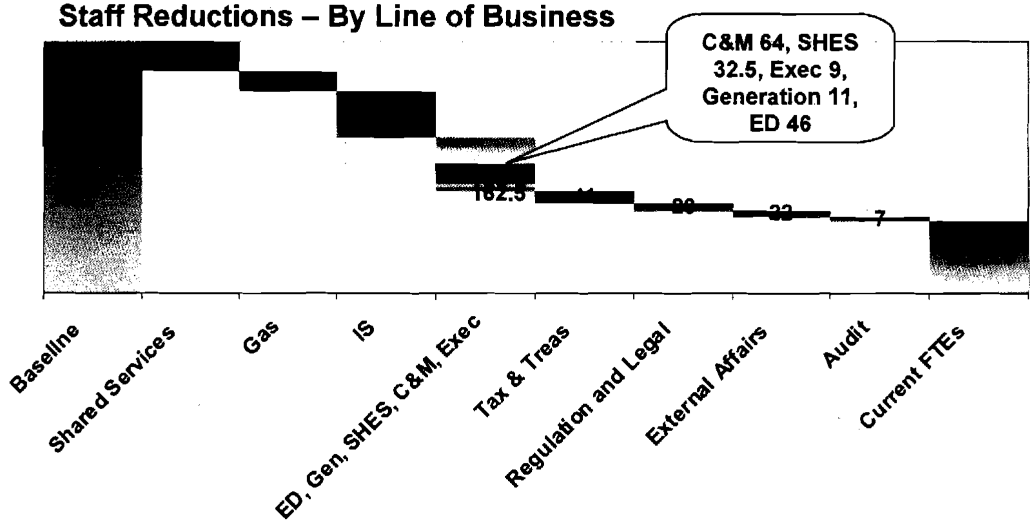
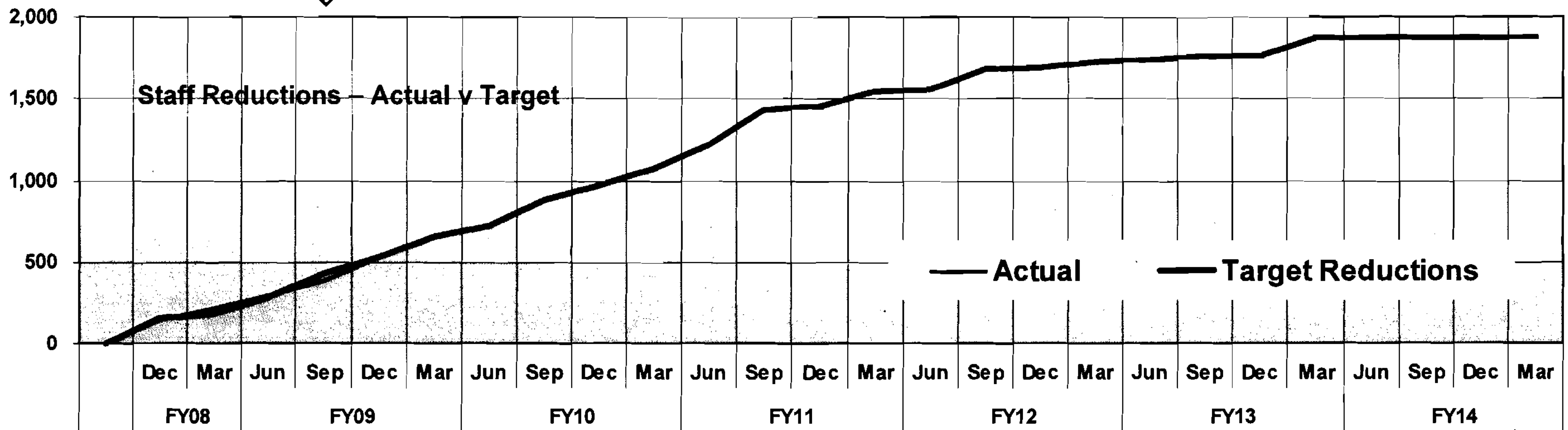
Synergy Savings Tracking to 31st December 2008:
FTE Bridge & Tracking to 31st December slightly ahead of target

Staff Reductions – By Line of Business



- 540 employee positions eliminated as of 31st December 2008; 66 ahead of schedule
- Electric Distribution and IS were key contributors although the AMR project and revision of initiatives in customer and markets have led to some re-phasing.
- Double manning is assumed to be charged as exceptional and therefore not impacting synergies or the headcount validation



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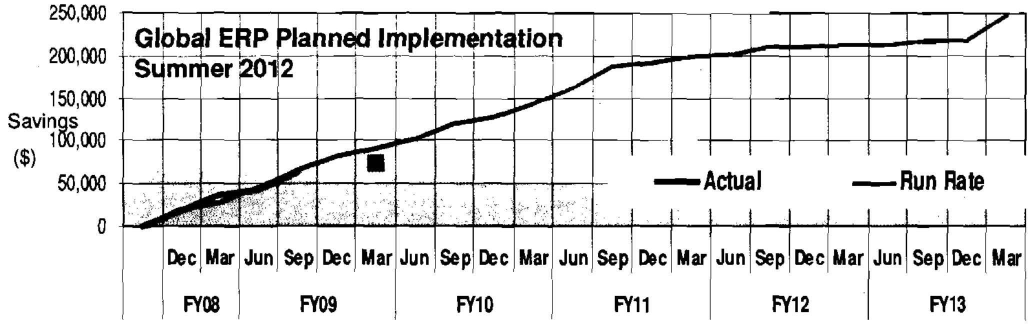
Appendix 4 Savings Tracking to 30th September:
Savings slightly behind target and fall short of $100M commitment as of Mar 2009

OPEX Reductions $ in Millions	Fiscal Year Basis 08/09 Q1 and Q2 Act	Var	Run Rate Basis As at Sept 08 Act	Var	Run Rate Basis As at Mar 09 F'cast	Var	Day N Target
Shared Services	$3.7	$0.9	$9.6	$2.8	$12.4	$3.9	$52.3
Gas Distribution	$2.2	($4.0)	$8.4	($6.9)	$19.6	($3.6)	$47.9
Information Services	$2.6	$0.0	$5.8	$0.0	$11.0	$2.4	$41.0
Customers and Markets	$3.8	($0.1)	$9.1	($1.1)	$10.5	($1.4)	$37.8
Electric Distribution	$1.1	($0.0)	$2.7	$0.0	$6.6	$0.9	$20.1
Tax, Treas. & Decision Support	$2.8	$0.8	$5.9	$1.7	$8.0	$1.0	$15.4
Regulation and Legal	$3.0	$0.6	$6.0	$1.2	$6.6	($2.1)	$12.0
Executive	$2.9	($0.6)	$5.8	($2.0)	$5.8	($2.0)	$7.8
SHES	$1.9	$1.7	$3.8	$2.7	$4.3	$0.3	$5.0
External Affairs	$2.4	$0.2	$4.8	$0.3	$4.8	$0.2	$4.8
Generation	$0.6	($0.0)	$1.2	($0.1)	$1.2	($0.1)	$1.7
Group Audit	$0.7	$0.2	$1.4	$0.5	$1.4	$0.5	$1.2
OPEX	**$27.6**	**($0.1)**	**$64.7**	**($0.9)**	**$92.2**	**($0.2)**	**$246.9**
Bad Debts	**$1.6**	**($1.0)**	**$2.9**	**($3.8)**	**$10.1**	**($2.2)**	**$40.7**
Grand Total	**$29.2**	**($1.1)**	**$67.6**	**($4.7)**	**$102.3**	**($2.4)**	**$287.6**



City Promise: $100M run rate target at the end of the first full year

- Two key projects are driving total savings to fall behind target. The AMR (Gas) project has been significantly scaled back as it did not receive the required regulatory approvals and Contact Center initiatives (Customer & Markets) are behind schedule. Consolidation schedule has been impacted by labor and system dependencies. Outsourcing strategy being reevaluated based on vendor cost and performance issues
- Within Regulation and Legal, the planned reduction in outside legal costs are not forecast to be attained by March 09 due to increased costs for new Rate Cases
- Executive is behind target as 8 positions have been eliminated compared to the original plan of 13
- The effect of the above projects has been partially offset by the acceleration of a number of other initiatives.
  - Surrender of three floors from Metrotech, acceleration of Supply Chain initiatives and transition of Finance resulting in a favorable position for Shared Services
  - Information Services is benefiting from contract volume discounts and various infrastructure projects
  - Tax, Treasury and Decision Support are ahead of plan due to the elimination of overlapping staff and departments
  - SHEs, Corporate Affairs, Group Audit and Generation have all achieved their Day N FTE target ahead of schedule
- The AMR (Gas) project has been significantly scaled back as it did not receive the necessary regulatory approvals. Plans are in place to achieve a run rate of $16.3M by March 09 and in addition 50% of the AMR shortfall or $3.3M has been added back as a task. Gas Distribution is in the process of filing with the NYPSC for regulatory approval for a smaller AMR program.
- Contact Center consolidation, virtualization and cost structure efficiencies will be achieved as long as dependencies noted above are successfully addressed. Overall contact center costs have been hampered by significantly increased call volumes and call complexity due to the economic environment.

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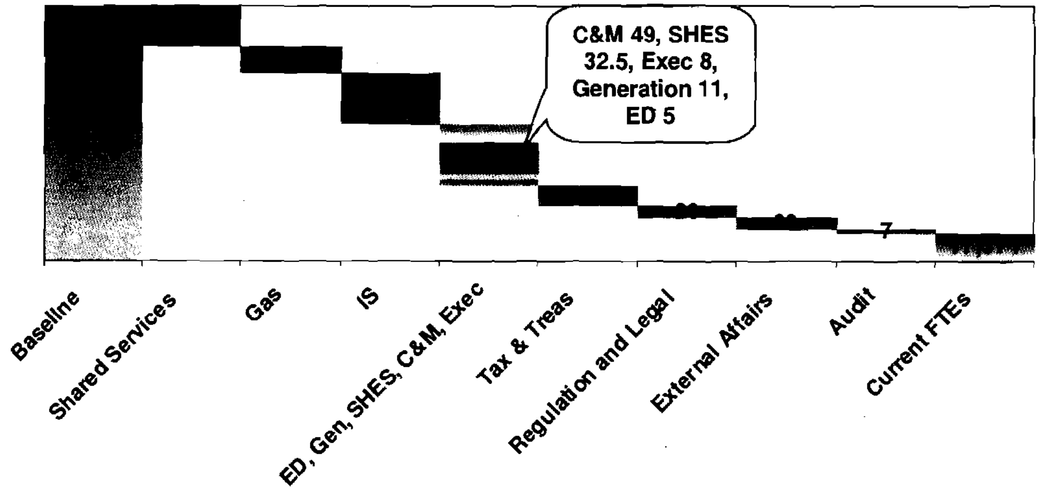
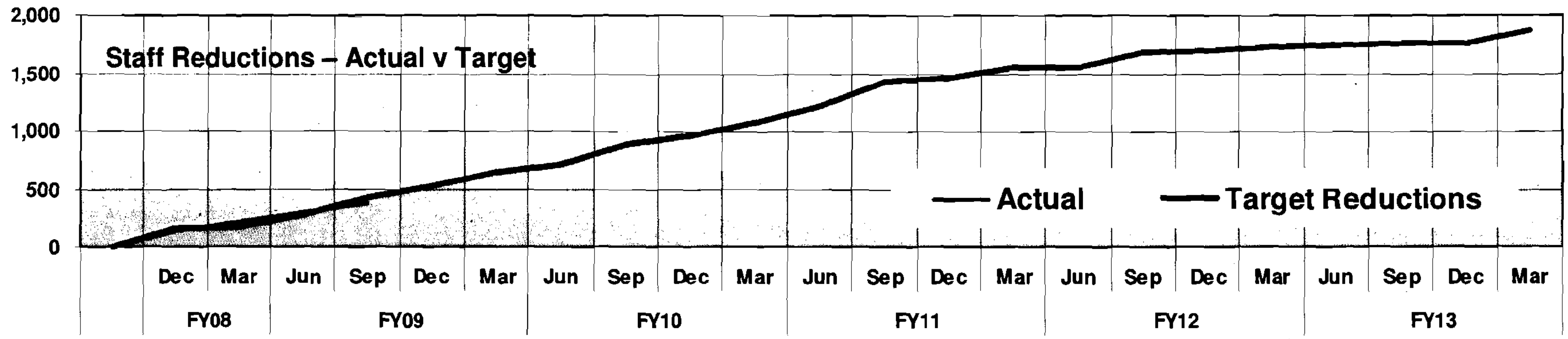
Appendix 4 Savings Tracking to 30th September:
FTE Bridge & Tracking to 30th September behind target

Staff Reductions – By Line of Business



- 388 employee positions eliminated as of 30th September 2008; 37 behind schedule
- Principal issues are the AMR project, Outsourcing Contact Center and the increased volume and complexity of calls
- Double manning is assumed to be charged as exceptional and therefore not impacting synergies or the headcount validation



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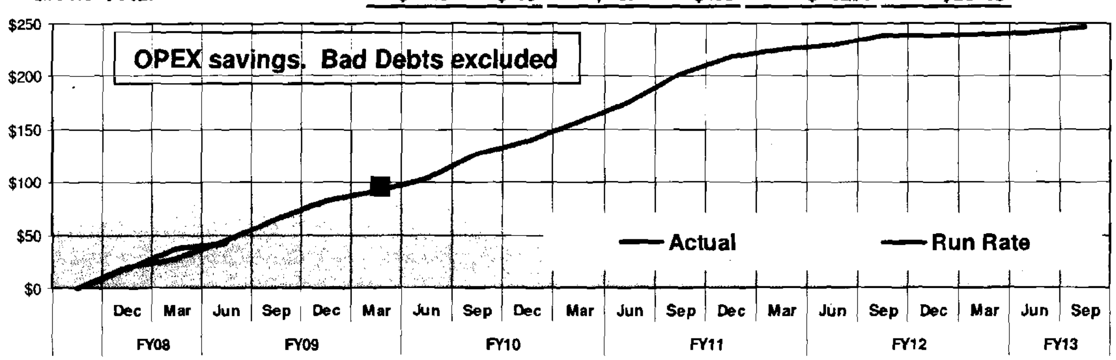
Savings Tracking to 30th June: OPEX Savings slightly behind target and fall short of **$100**M commitment as of Mar 2009.

OPEX Reductions $ in Millions	Fiscal Year Basis FY 08/09 Q1 Act	 Var	Run Rate Basis As at June 08 Act	 Var	Target Run Rate Mar 09	Day N Target
Shared Services	$1.5	$0.5	$6.2	$2.3	$8.3	$52.1
Gas Distribution	$0.5	$1.8	$4.2	$5.2	$8.3	$47.9
Information Services	$1.1	$0.1	$4.2	$0.3	$8.3	$43.8
Customers and Markets	$1.1	$0.8	$7.7	$0.1	$8.3	$40.5
Electric Distribution	$0.7	$0.2	$1.7	$0.0	$8.3	$20.1
Tax, Treas. & Decision Support	$0.5	$0.5	$2.1	$1.8	$8.3	$12.9
Regulation and Legal	$1.6	$0.4	$6.4	$1.7	$8.3	$12.0
Executive	$1.5	$0.1	$5.8	$0.4	$8.3	$7.8
SHES	$0.9	$1.0	$3.6	$4.0	$8.3	$5.0
External Affairs	$0.1	$0.3	$0.4	$1.1	$8.3	$2.1
Generation	$0.3	$0.0	$1.2	$0.0	$8.3	$1.7
Group Audit	$0.4	$0.1	$1.5	$0.5	$8.3	$1.2
OPEX	**$10.1**	**$1.3**	**$45.0**	**$0.3**	**$100.1**	**$246.9**
Bad Debts	**$0.9**	**$0.0**	**$2.9**	**$0.7**	**$12.3**	**$40.7**
Grand Total	**$10.9**	**$1.3**	**$48.0**	**$1.0**	**$112.4**	**$287.6**



■ **City Promise: $100m run rate target at the end of the first full year**

- Savings falling behind target due to delays in implementation of certain synergy saving initiatives. Plans are being developed to catch up and exceed the re-phased OPEX run rate, after adjusting for P1, of $92.5M as of March 2009.
- Within Gas Distribution, the AMR project is behind schedule: The NYC and LI programs are currently under internal evaluation. To move forward, PSC approval would then still need to be granted for each program. The AMR project was targeted to generate a Run Rate of $ 6.5M at March 09. Replacement initiatives are being fast tracked to bring the savings back in line with the targets.
- Reported savings exclude savings from the surrender of three floors at Metrotech scheduled in Q2 and Q3. This will add $ 3.0M to the run rate.
- FTE savings of 297 are being reported against the 2006 baseline used for Integration.
- Drivers
  - Elimination of posts not in Day N structures
  - Elimination of senior executive overlaps
  - Elimination of duplicative positions within LoBs
  - Elimination of KSE Board of Directors
  - Elimination of Stock Listing Fees
- Headcount reconciliation from 2006 baseline to 08/09 budget has been completed and validates the savings.
- Double manning assumed to be charged as exceptional and therefore not impacting synergies.
- Bad debt savings reported are the estimated impacts of remediation strategies implemented.... But the underlying debt expense run rate (both charge offs & provision movements) is running well ahead of integration assumptions.

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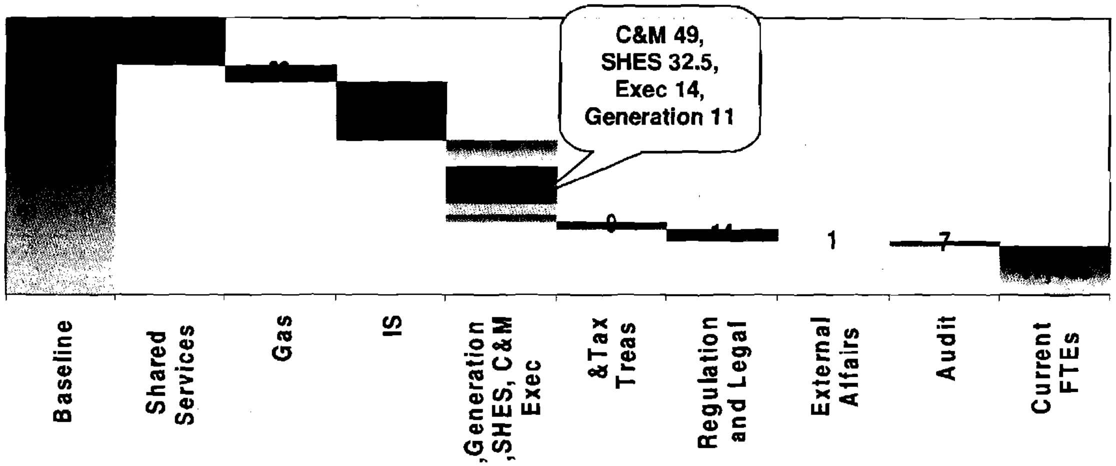
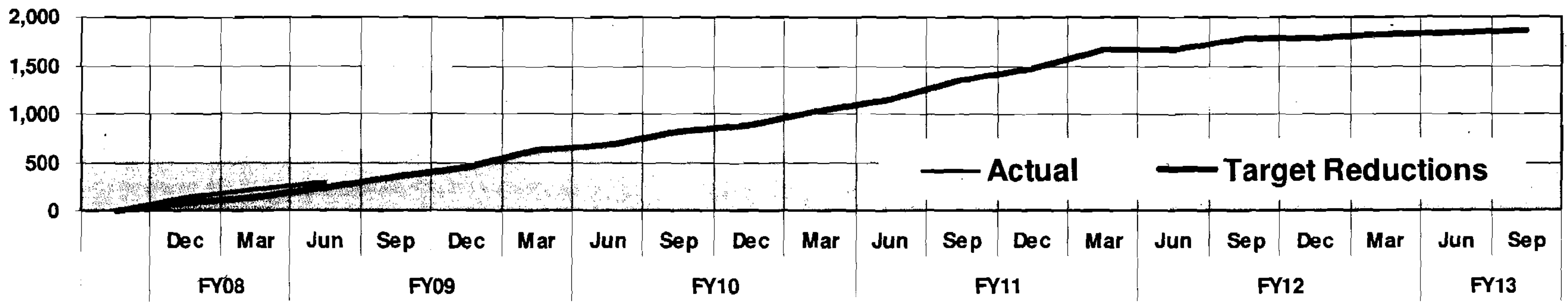
FTE Bridge & Tracking to 30th June
Tracking ahead of target. Validation complete.



- 297 employee positions eliminated as of 30th June 2008; 8 ahead of schedule
- Headcount reconciliation from 2006 to 08/09 budget validates all reported synergy savings.



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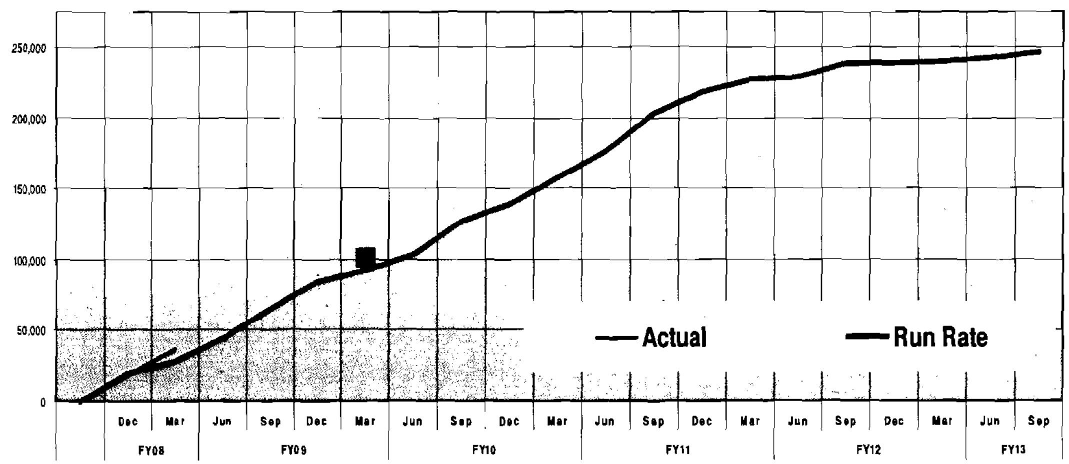
Savings Tracking to 31st March: Initial View
Savings ahead of target but fall slightly short of $100M commitment as of Mar 2009.
Headcount is the key driver across all groups.

OPEX Reductions $ in Millions	Fiscal Year Basis: FY08 Year End Act	Target	Var	Run Rate Basis: Run Rate at Mar 08 Act	Target	Var	Day N Target
Shared Services	$3.5	$0.2	$3.3	$5.5	$0.4	$5.1	$52.1
Gas Distribution	$2.1	$2.3	($0.2)	$3.8	$5.8	($2.0)	$47.9
Information Services	$2.4	$1.8	$0.6	$4.2	$3.9	$0.3	$43.8
Customers and Markets	$2.1	$1.3	$0.7	$3.6	$2.8	$0.8	$40.5
Electric Distribution	$0.3	$0.2	$0.0	$0.2	$0.7	($0.5)	$20.1
Tax ,Treas. & Decision Suppor	$0.9	$1.7	($0.7)	$2.0	$3.5	($1.5)	$12.9
Regulation and Legal	$1.9	$1.9	($0.0)	$6.4	$4.0	$2.4	$12.0
Executive	$2.6	$1.3	$1.3	$5.8	$4.0	$1.8	$7.8
SHES	$0.6	$0.0	$0.6	$2.5	$0.1	$2.5	$5.0
External Affairs	$0.2	$0.1	$0.0	$0.4	$0.4	$0.0	$2.1
Generation	$0.3	$0.6	($0.3)	$1.2	$1.2	$0.0	$1.7
Group Audit	$0.5	$0.5	$0.0	$1.5	$0.9	$0.5	$1.2
Sub Total	$17.4	$11.9	$5.5	$37.1	$27.7	$9.4	$246.9
Bad Debts	$0.4	$0.7	($0.4)	$1.2	$2.0	($0.8)	$40.7
Grand Total	$17.8	$12.7	$5.1	$38.3	$29.7	$8.6	$287.6



■ City Promise: $100m run rate target at the end of the first full year

- Savings are ahead of target but the re-phased run rate, after adjusting for P1, is $92.4M as of March 2009 falling slightly short of $100M commitment
- FTE savings are being reported against the 2006 baseline used for Integration
- Drivers
  - Elimination of posts not in Day N structures
  - Elimination of senior executive overlaps
  - Elimination of duplicative positions within LoBs
  - Elimination of KSE Board of Directors
  - Elimination of Stock Listing Fees
- Headcount reconciliation from 2006 baseline to 08/09 budget has been completed and validates the reported savings.
- Double manning (duplicate headcount carried for a short period to facilitate the transfer of work between locations) assumed to be charged as an exceptional and therefore not impact synergies. Double manning being recorded as part of 08/09 budget uploads. Key risk – large population of internal postings means that all double manning may not be "incremental" on a company basis and therefore not treated as exceptional
- Bad debt savings reported are the estimated impacts of remediation strategies implemented.... But the underlying debt expense run rate (both charge offs & provision movements) is running well ahead of integration assumptions

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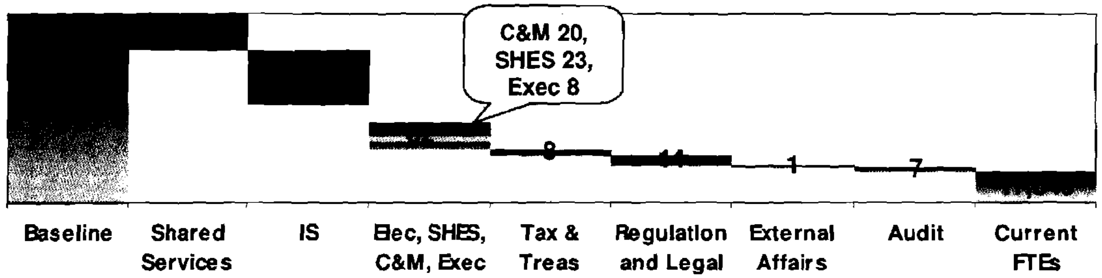
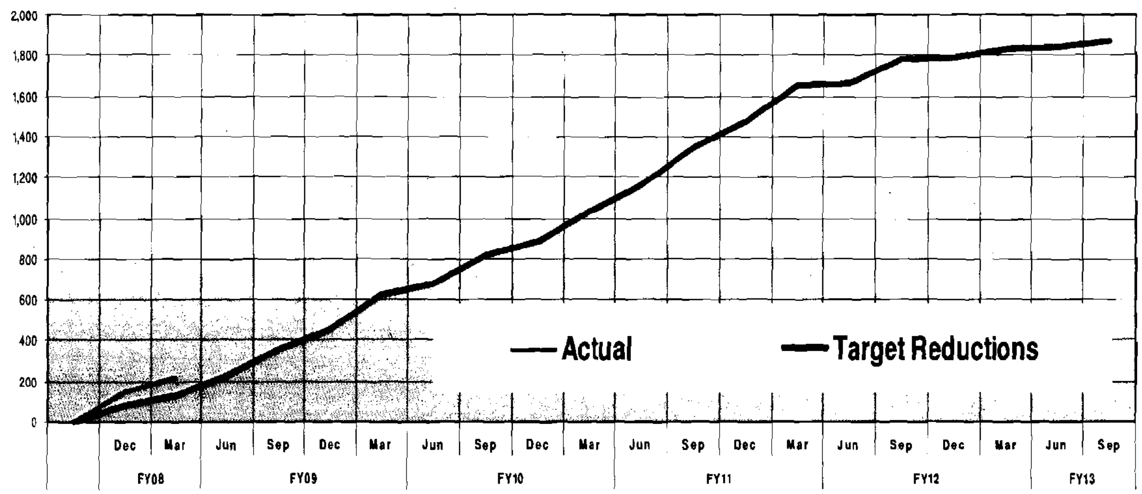
FTE Bridge & Tracking to 31st March
Tracking ahead of target   Validation complete



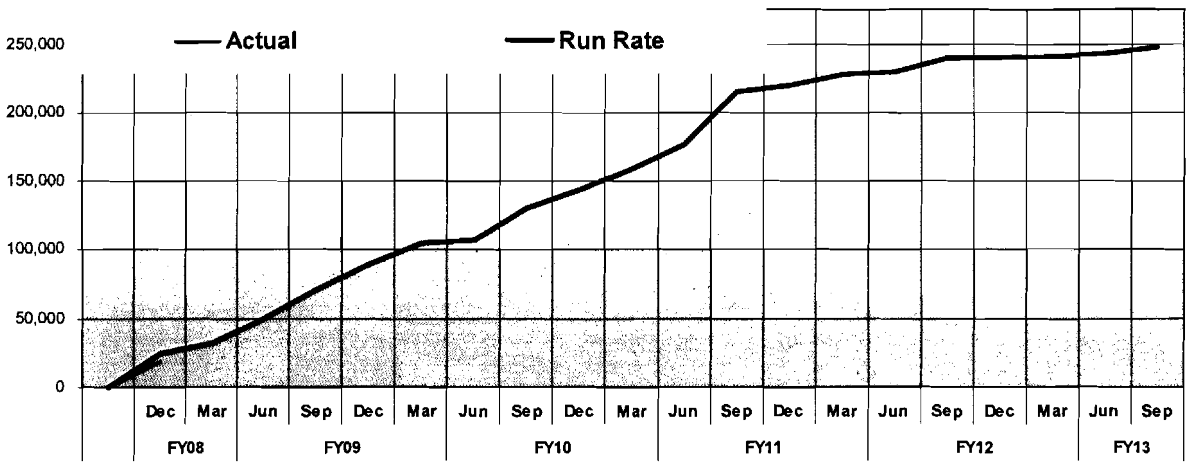


- 217 employee positions eliminated as of March 31, 2008; 31 ahead of schedule
- Headcount reconciliation from 2006 to 08/09 budget validates all reported synergy savings

US Integration Synergies

Summary Savings - Preliminary Tracking to December 2007

OPEX Reductions $ in Millions	Qtr Dec 07 Act	Qtr Dec 07 Target	Qtr Dec 07 Var	FY08 Year End Act	FY08 Year End Target	FY08 Year End Var	Run Rate Act	Run Rate Target	Run Rate Var	Day N Target
Shared Services	$0.3	$0.1	$0.2	$0.8	$0.2	$0.6	$3.5	$0.4	$3.2	$52.1
Gas Distribution	0.8	0.8	0.0	2.3	2.3	0.0	3.2	3.2	0.0	47.9
Information Services	0.9	0.8	0.1	1.6	1.8	(0.2)	3.2	3.4	(0.2)	43.8
Customers and Markets	0.7	0.7	0.0	1.4	1.3	0.0	2.7	2.6	0.1	40.5
Regulation and Legal	1.3	0.9	0.5	1.9	1.9	0.0	3.2	3.5	(0.3)	12.0
Executive	0.5	0.3	0.2	1.1	1.3	(0.2)	2.5	1.2	1.3	7.8
Total	$4.5	$3.6	$0.9	$9.0	$8.8	$0.2	$18.3	$14.2	$4.0	$204.1
Electric Distribution		0.1			0.2			0.2		20.1
Tax & Treasury		0.8			1.7			3.1		12.9
SHES		0.0			0.0			0.1		5.0
External Affairs		0.1			0.1			0.2		2.1
Generation		0.3			0.6			1.1		1.7
Group Audit		0.2			0.5			0.9		1.2
Total		1.4			3.1			5.7		42.9
Total		$5.0			$11.9			$20.0		$246.9



- **All Businesses are committed to achieving 100% of Synergy Savings embedded into budgets**
- **Business Units currently reporting actual Synergy Savings to date**
  - **Shared Services**
  - **Gas Distribution**
  - **Information Services**
  - **Customers and Markets**
  - **Regulation and Legal**
  - **Executive**
- **Business Units developing a rigorous Synergy Savings tracking process**
  - **Electric Distribution**
  - **Tax & Treasury**
  - **SHES**
  - **External Affairs**
  - **Generation**
  - **Group Audit**

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Date of Request: February 5, 2010
Due Date: February 15, 2010

Request No. DPS-15(RAV-11 a,k,l)
NMPC Req. No. NM 15

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO:

Request:

Attached to this IR is a January 5, 2010 Syracuse Post Standard Letter to the Editor from the Company's Susan Crossett. Regarding this letter as it relates to the Company's Information Systems (IS) department, please provide the following information:
A. Provide a breakdown of National Grid's 2007, 2008 and 2009 IS department costs by cost-component and by affiliate, both regulated and unregulated. Include all affiliates even if no IS costs were allocated to some of them. Include percentages as well as dollars.
K. Same as A. for the rate year forecast.
L. As related to this IS study, fully explain and quantify how the rate year forecast reflects "ways to improve performance and control costs for the benefit of customers," as stated in the January 5, 2010 Syracuse Post Standard Letter to the Editor, attached as RAV-11 Attachment. Include supporting workpapers and tie-ins to rate case exhibits

Response:

A. Please refer to Attachment 1.

K. The rate year forecast does not include a specific forecast for the IS department. The Company used the historic test year cost allocations as the basis for the rate year cost allocations.

L. IS performance improvements and cost control measures are captured in the overall rate year productivity adjustment and synergy savings adjustment. There are no discrete savings for the IS department.

Name of Respondent:
James M. Molloy

Date of Reply:
February 14, 2010

Form 103

Date of Request: February 9, 2010
Due Date: February 19, 2010

Request No. RAV-13
NMPC Req. No. NM 18 DPS 18

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO:

Request:

A. For each month, January 2006 through December 2009, please provide a breakdown of total service company costs charged to every individual affiliate of National Grid, both regulated and unregulated; also include 2006 – 2009 annual amounts. Please provide this information broken down between those costs allocated from the National Grid – USA service company, the KeySpan service company, and in total.
B. Same as A, for the rate years' forecasted amounts.
C. Please provide monthly updates for A. above until further notice.
Note: Please provide the information in an excel spreadsheet, not a pdf file.

Response:

A. Please see Attachment 1 (Attachment 1 to RAV-13.xls). Also, please note that the charges to affiliates from the 3 KeySpan service companies are consolidated.

B. The forecast for the rate years does not include a specific forecast of service company allocated charges to individual companies. The Company used the historic test year cost allocations as the basis for the allocated charges in the rate years.

C. Monthly updates to be provided as requested.

Name of Respondent:
Andrew Sloey

Date of Reply:
February 19, 2010

Form 103

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Annual Amounts Charged from National Grid & KeySpan Service Companies to Affiliates

	Charged Company	2006	2007	2008	2009	
00001	National Grid USA	6,892,894	7,207,027	9,078,845	4,017,730	27,196,495
00004	Nantucket Electric Company	2,120,106	1,892,196	1,985,566	2,024,569	8,022,437
00005	Massachusetts Electric Company	156,715,567	165,330,427	202,227,835	238,723,445	762,997,275
00006	NE Hydro - Trans Electric Co	3,208,133	3,311,213	3,651,055	3,486,402	13,656,803
00007	New England Hydro Finance Co	-	109	443	(31)	521
00008	New England Hydro - Trans Corp	1,060,162	1,205,537	970,382	1,049,859	4,285,940
00010	New England Power Company	42,417,423	44,234,131	51,444,171	60,031,910	198,127,636
00020	New England Electric Trans Co	837,531	592,685	421,005	(660,671)	1,190,551
00021	National Grid Trans Services	7,302	115,682	37,651	36,895	197,530
00035	Niagara Mohawk Holdings, Inc.	859	7,572	18,209	43,407	70,047
00036	Niagara Mohawk Power Corp	192,708,260	230,215,297	271,807,390	349,469,851	1,044,200,798
00037	Opinac North America, Inc	3,298	3,911	375	-	7,584
00041	Granite State Electric Company	5,365,037	6,534,089	7,206,804	7,920,041	27,025,972
00048	Narragansett Gas Company	5,828,034	21,239,945	29,500,058	36,724,474	93,292,511
00049	Narragansett Electric Company	59,287,685	63,198,136	74,930,270	79,845,549	277,261,640
00070	Wayfinder Group Inc.	9,144	12,518	16,890	58,962	97,514
00071	Valley Appliance & Merchandise	737	6,623	6,514	1,207	15,081
00072	National Grid Billing Entity	4,523,622	4,651,381	6,216,091	4,991,884	20,382,978
00075	NEES Communications, Inc.	301	-	-	-	301
00076	NGrid Communications Billing	2,304,578	1,692,712	(67,303)	-	3,929,988
00077	Grid Communications Inc	225	-	-	-	225
00078	Atlantic Western Consulting	160	-	-	-	160
00079	National Grid Wireless Cons	(2,957)	1,593	-	-	(1,363)
00082	GridAmerica Holdings	(9,147)	43,816	2,137	64,617	101,423
00083	GridAmerica LLC	124,056	-	-	-	124,056
00085	NEES Energy, Inc.	10,732	8,258	8,272	13,477	40,739
00086	EUA Energy Investment	2,418	2,472	2,740	6,191	13,820
00092	Prudence Corporation	515	211	53	268	1,046
00093	Patience Corporation	20	208	2,490	347	3,065
00094	Newport America Corporation	242	601	268	896	2,006
00095	Metrowest Realty LLC	1,581	2,549	9,054	20,306	33,490
00402	Essex Gas Company	-		21,439	90,082	111,521
00457	KeySpan Energy Services Inc.	-	-	2,893	-	2,893
00460	KeySpan Corporation	-	-	156,810	1,806	158,617
01401	Boston Gas Company Billing BU	-	25,637,149	87,675,910	90,103,320	203,416,379
01402	ESSEX COUNTY GAS COMPANY	-	64,904	378,634	850,180	1,293,719
01403	Colonial Lowell Div Billing BU	-	5,516,845	18,496,186	18,986,444	42,999,475
01404	Colonial Cape Cod Billing BU	-	156,995	878,657	504,494	1,540,146
01406	EnergyNorth Nat Gas Billing BU	-	3,111,446	10,913,308	10,889,618	24,914,372
01407	KEYSPAN NEW ENGLAND LLC	-	55,803	124,449	268,070	448,322
01429	KEYSPAN MONEY POOLS	-	4,656,100	10,283,490	3,006,793	17,946,383
01431	KeySpan Corp Serv Billing BU	-	423	45,695	37,226	83,345
01434	KeySpan Electric Srv BillingBU	-	41,470,933	147,264,159	154,132,965	342,868,056
01435	KeySpan Generation Billing BU	-	18,395,152	65,774,605	77,420,670	161,590,427
01436	KeySpan Energy Dev Billing BU	-	1,500,419	4,668,341	5,030,199	11,198,958
01437	KS Gas East Corp KEDLI Bill BU	-	27,663,982	97,478,708	95,945,499	221,088,189
01438	Brklyn Union Gas KEDNY Bill BU	-	40,633,919	146,358,908	153,523,730	340,516,558
01441	TRANSCANADA RAVENSWOOD	-	-	35,674	-	35,674
01442	KS Ravenswood Srvcs Billing BU	-	10,462,341	23,236,775	706,366	34,405,482
01444	KS Energy Trading Billing BU	-	1,367,536	6,144,594	3,898,926	11,411,056
01446	KS Glenwood Energy Billing BU	-	536,084	2,545,695	2,549,096	5,630,875
01448	KS Port Jeff Energy Billing BU	-	822,521	2,687,566	2,753,923	6,264,010
01457	KEYSPAN ENERGY SERVICES INC.	-	183,645	384,450	(334)	567,761
01458	KS Energy Supply Billing BU	-	1,041,099	1,717	25	1,042,841
01459	KS Services Billing BU	-	3,799,786	15,143,491	12,053,853	30,997,130
01460	KEYSPAN ENERGY CORP	-	(7,615,531)	(20,658,581)	(20,071,787)	(48,345,900)
01471	Seneca Upshur Billing BU	-	187,893	1,376,326	978,489	2,542,708
82	NG RAVENSWOOD SERV (post Sale)	-	-	10,042,797	5,950,934	15,993,732
01563	KeySpan E&P JV Billing BU	-	11,005	29,121	39,283	79,409
C4	KEYSPAN LNG LP REGULATED ENTITY	-	-	(3,177)	-	(3,177)
D1	TRANSGAS	-	-	-	6,685	6,685
NK	NGUSA Service Company, Inc.	-	-	1,556	-	1,556
Total		$483,418,520	$731,171,347	$1,290,967,461	$1,407,528,141	$3,913,085,469

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2006 Amounts Charged from National Grid & KeySpan Service Companies to Affiliates by Month

	Charged Company	January 2006	February 2006	March 2006	April 2006	May 2006	June 2006	July 2006	August 2006	September 2006	October 2006	November 2006	December 2006	
00001	National Grid USA	$406,324	$381,815	$2,417,722	$383,781	$546,688	$328,368	$264,368	$414,103	$435,979	$332,907	$344,056	$636,783	$6,892,894
00004	Nantucket Electric Company	144,269	150,313	205,773	161,335	192,839	216,836	171,892	257,639	152,392	173,634	162,867	130,316	2,120,106
00005	Massachusetts Electric Company	12,432,906	12,365,011	16,779,554	10,859,274	11,435,816	14,579,261	12,056,245	12,584,040	13,842,246	13,711,945	12,565,592	13,503,678	156,715,567
00006	NE Hydro - Trans Electric Co	250,737	246,494	295,195	288,260	255,470	251,562	261,695	237,577	261,945	308,074	272,342	278,784	3,208,133
00007	New England Hydro Finance Co	-	-	-	102	-	(102)	-	-	-	-	-	-	-
00008	New England Hydro - Trans Corp	77,421	55,650	181,745	120,362	56,581	73,820	114,182	79,879	63,575	87,740	68,280	80,927	1,060,162
00010	New England Power Company	3,762,216	3,505,636	4,505,331	3,288,712	3,131,594	3,637,966	3,284,776	3,742,823	3,229,922	3,428,763	3,558,392	3,341,293	42,417,423
00020	New England Electric Trans Co	50,609	57,342	65,552	102,844	75,740	64,722	75,283	62,603	56,961	98,448	65,085	62,342	837,531
00021	National Grid Trans Services	138	117	1,601	590	591	631	751	569	484	637	584	609	7,302
00035	Niagara Mohawk Holdings, Inc.	-	-	9	-	-	-	-	-	138	296	416	-	859
00036	Niagara Mohawk Power Corp	16,611,944	13,956,090	13,735,099	12,800,442	14,372,174	15,412,970	16,031,225	14,996,347	16,066,770	20,103,242	20,293,489	18,328,468	192,708,260
00037	Opinac North America, Inc	-	-	1,544	-	1,390	109	-	-	-	255	-	-	3,298
00041	Granite State Electric Company	453,665	427,982	549,632	447,791	413,909	461,141	399,262	441,821	453,156	460,355	422,366	433,957	5,365,037
00048	Narragansett Gas Company	-	-	-	-	-	-	-	7,773	1,247,535	1,751,462	1,250,248	1,571,017	5,828,034
00049	Narragansett Electric Company	4,660,564	4,695,614	5,665,534	4,039,097	4,471,798	5,269,656	4,932,481	5,104,422	5,437,030	5,367,167	4,706,054	4,938,269	59,287,685
00070	Wayfinder Group Inc.	311	221	1,698	1,677	644	1,004	885	700	738	707	637	(78)	9,144
00071	Valley Appliance & Merchandise	-	-	-	-	-	-	-	-	20	717	-	-	737
00072	National Grid Billing Entity	291,215	75,262	342,155	542,616	353,520	703,669	553,620	369,865	266,936	142,780	378,992	502,989	4,523,622
00075	NEES Communications, Inc.	301	-	-	-	-	-	-	-	-	-	-	-	301
00076	NGrid Communications Billing	337,420	138,085	175,722	226,695	200,564	(19,535)	200,497	224,338	216,784	221,836	214,734	167,440	2,304,578
00077	Grid Communications Inc	222	-	3	-	-	-	-	-	-	-	-	-	225
00078	Atlantic Western Consulting	158	-	2	-	-	-	-	-	-	-	-	-	160
00079	National Grid Wireless Cons	-	(3,207)	31	300	-	-	-	(80)	-	-	-	-	(2,957)
00082	GridAmerica Holdings	461	(177)	(7,501)	40,013	4,390	(14,518)	(2,858)	(4,111)	(10,677)	(11,872)	(698)	(1,600)	(9,147)
00083	GridAmerica LLC	111,191	3,948	8,917	-	-	-	-	-	-	-	-	-	124,056
00085	NEES Energy, Inc.	217	351	2,969	876	574	729	554	513	2,377	595	580	398	10,732
00086	EUA Energy Investment	26	15	1,222	429	149	476	(295)	151	195	290	178	(418)	2,418
00092	Prudence Corporation	-	-	-	-	-	-	-	-	20	495	-	-	515
00093	Patience Corporation	-	-	-	-	-	-	-	-	20	-	-	-	20
00094	Newport America Corporation	-	-	-	-	-	-	-	-	20	222	-	-	242
00095	Metrowest Realty LLC	40	44	476	151	151	151	(126)	151	218	197	192	(63)	1,581
Total		$39,592,355	$36,056,606	$44,929,984	$33,305,346	$35,514,584	$40,968,916	$38,344,435	$38,521,121	$41,724,783	$46,180,893	$44,304,387	$43,975,110	$483,418,520

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2007 Amounts Charged from National Grid & KeySpan Service Companies to Affiliates by Month

	Charged Company	January 2007	February 2007	March 2007	April 2007	May 2007	June 2007	July 2007	August 2007	September 2007	October 2007	November 2007	December 2007	
00001	National Grid USA	401,048	401,692	699,572	409,886	418,881	427,064	458,700	1,260,687	427,553	762,296	469,063	1,070,585	7,207,027
00004	Nantucket Electric Company	186,506	177,075	293,682	105,626	131,332	123,695	137,321	204,723	113,100	128,639	144,696	145,801	1,892,196
00005	Massachusetts Electric Company	12,254,659	12,734,934	19,600,885	10,796,235	13,211,714	13,912,576	13,239,891	14,404,977	12,925,708	14,248,587	14,111,698	13,888,563	165,330,427
00006	NE Hydro - Trans Electric Co	311,949	245,638	342,911	264,203	258,341	386,425	269,199	260,746	228,395	251,745	295,911	195,749	3,311,213
00007	New England Hydro Finance Co	-	-	-	-	-	-	109	-	-	-	-	-	109
00008	New England Hydro - Trans Corp	85,370	84,528	161,363	149,349	72,919	94,238	71,714	105,320	65,472	149,723	92,397	73,144	1,205,537
00010	New England Power Company	3,219,663	3,454,978	4,815,187	3,024,044	3,403,562	3,404,226	3,579,362	4,019,837	4,113,053	3,579,510	4,088,951	3,531,759	44,234,131
00020	New England Electric Trans Co	68,340	57,788	65,689	59,297	46,970	52,858	33,487	39,695	39,210	41,847	52,395	35,109	592,685
00021	National Grid Trans Services	545	462	336	401	357	427	1,188	123,625	(20,269)	2,202	3,547	2,861	115,682
00035	Niagara Mohawk Holdings, Inc.	-	-	-	-	-	-	-	-	-	-	-	7,572	7,572
00036	Niagara Mohawk Power Corp	19,218,946	18,380,328	21,978,954	13,746,287	18,689,214	16,479,492	19,806,665	21,422,162	19,370,108	21,130,748	19,342,718	20,649,673	230,215,297
00037	Opinac North America, Inc	-	5	667	-	1,860	-	1,380	-	-	-	-	-	3,911
00041	Granite State Electric Company	457,432	403,645	753,213	439,172	471,606	889,492	440,833	563,014	405,191	592,446	607,051	510,995	6,534,089
00048	Narragansett Gas Company	1,562,086	1,445,889	2,012,064	1,371,306	1,396,912	1,794,893	1,628,565	2,109,684	1,561,678	2,699,704	1,877,346	1,779,817	21,239,945
00049	Narragansett Electric Company	4,980,156	4,820,678	7,487,973	4,092,107	4,964,642	5,123,707	4,962,673	5,352,535	5,104,066	5,146,994	5,766,327	5,396,279	63,198,136
00070	Wayfinder Group Inc.	1,505	714	2,072	858	696	690	(83)	641	(124)	411	1,437	3,702	12,518
00071	Valley Appliance & Merchandise	50		504	304	380	1,101	368	464	782	413	375	1,880	6,623
00072	National Grid Billing Entity	228,523	386,954	265,160	348,446	312,855	399,138	299,493	340,843	391,597	351,317	587,289	739,766	4,651,381
00076	NGrid Communications Billing	203,053	188,159	207,428	226,407	269,026	212,448	198,190	117,181	2,940	68,021	(139)	-	1,692,712
00079	National Grid Wireless Cons	1,593	-	-	-	-	-	-	-	-	-	-	-	1,593
00082	GridAmerica Holdings	2,002	1,825	29,911	2,064	3,013	4,940	14,858	-	-	(14,797)	-	-	43,816
00085	NEES Energy, Inc.	778	1,604	493	614	706	570	316	564	551	866	650	545	8,258
00086	EUA Energy Investment	176	354	(248)	434	173	174	264	223	216	222	267	217	2,472
00092	Prudence Corporation	50	-	161	-	-	-	-	-	-	-	-	-	211
00093	Patience Corporation	50	-	158	-	-	-	-	-	-	-	-	-	208
00094	Newport America Corporation	50	-	106	-	444	-	-	-	-	-	-	-	601
00095	Metrowest Realty LLC	189	182	(1)	344	359	415	(500)	240	199	270	670	182	2,549
01401	Boston Gas Company Billing BU	-	-	-	-	-	-	-	-	8,245,067	4,791,378	6,310,964	6,289,740	25,637,149
01402	ESSEX COUNTY GAS COMPANY									26,963	(3,546)	27,784	13,703	64,904
01403	Colonial Lowell Div Billing BU	-	-	-	-	-	-	-	-	1,804,875	1,052,422	1,354,556	1,304,993	5,516,845
01404	Colonial Cape Cod Billing BU	-	-	-	-	-	-	-	-	59,784	25,967	47,802	23,442	156,995
01406	EnergyNorth Nat Gas Billing BU	-	-	-	-	-	-	-	-	1,030,861	583,544	787,156	709,884	3,111,446
01407	KEYSPAN NEW ENGLAND LLC									37,795	479	9,912	7,617	55,803
01429	KEYSPAN MONEY POOLS									1,799,915	1,254,063	887,210	714,913	4,656,100
01431	KeySpan Corp Serv Billing BU	-	-	-	-	-	-	-	-	-	-	-	423	423
01434	KeySpan Electric Srv BillingBU	-	-	-	-	-	-	-	-	12,247,825	8,315,566	9,848,739	11,058,802	41,470,933
01435	KeySpan Generation Billing BU	-	-	-	-	-	-	-	-	6,022,513	3,742,309	3,777,494	4,852,836	18,395,152
01436	KeySpan Energy Dev Billing BU	-	-	-	-	-	-	-	-	653,624	78,249	325,791	442,755	1,500,419
01437	KS Gas East Corp KEDLI Bill BU	-	-	-	-	-	-	-	-	7,893,159	6,042,699	6,419,056	7,309,069	27,663,982
01438	Brklyn Union Gas KEDNY Bill BU	-	-	-	-	-	-	-	-	11,749,295	8,267,717	9,857,450	10,759,457	40,633,919
01442	KS Ravenswood Srvcs Billing BU	-	-	-	-	-	-	-	-	3,275,009	1,956,005	2,564,130	2,667,198	10,462,341
01444	KS Energy Trading Billing BU	-	-	-	-	-	-	-	-	463,496	172,093	322,823	409,124	1,367,536
01446	KS Glenwood Energy Billing BU	-	-	-	-	-	-	-	-	250,202	16,643	121,280	147,960	536,084
01448	KS Port Jeff Energy Billing BU	-	-	-	-	-	-	-	-	203,510	324,887	142,016	152,109	822,521
01457	KEYSPAN ENERGY SERVICES INC.									59,657	34,447	36,007	53,534	183,645
01458	KS Energy Supply Billing BU	-	-	-	-	-	-	-	-	429,328	74,006	214,943	322,823	1,041,099
01459	KS Services Billing BU	-	-	-	-	-	-	-	-	1,135,720	905,464	917,965	840,637	3,799,786
01460	KEYSPAN ENERGY CORP									(2,149,166)	(1,880,149)	(1,824,986)	(1,761,230)	(7,615,531)
01471	Seneca Upshur Billing BU	-	-	-	-	-	-	-	-	75,661	15,447	50,857	45,928	187,893
01563	KeySpan E&P JV Billing BU	-	-	-	-	-	-	-	-	5,354	(205)	3,253	2,603	11,005
	Total	43,184,719	42,787,433	58,718,240	35,037,385	43,655,962	43,308,567	45,143,993	50,327,161	100,049,872	84,910,648	89,644,851	94,402,516	731,171,347

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2008 Amounts Charged from National Grid & KeySpan Service Companies to Affiliates by Month

	Charged Company	January 2008	February 2008	March 2008	April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	
00001	National Grid USA	837.787	921,405	3,370,873	195,173	864,561	493,869	404,171	358.981	538,560	312.292	232,478	548,696	9,078,845
00004	Nantucket Electric Company	173,905	257,601	149,212	172,253	162,280	165,317	135,738	117,946	234,307	166,127	135,232	115,648	1,985,566
00005	Massachusetts Electric Company	14,375,919	14,478,124	19,322,255	14,813,575	16,620,765	16,594,638	15,779,627	15,524,399	20,700,498	17,544,496	15,875,592	20,597,948	202,227,835
00006	NE Hydro - Trans Electric Co	280.132	255,402	214,018	263,932	366,287	314,670	380,074	262.510	249,560	517,773	271,725	274,970	3,651,055
00007	New England Hydro Finance Co	-	-	102	-	-	-	-	341	-	-	-	-	443
00008	New England Hydro - Trans Corp	153,305	47,477	161,039	61,043	66,626	81,622	56,664	58,058	118,210	59,225	63,022	44,092	970,382
00010	New England Power Company	4,160,567	3,729,709	5,087,696	3,684,194	4,376,188	4,120,936	3,757,447	3,875,895	5,338,971	4,424,986	4,673,718	4,213,864	51,444,171
00020	New England Electric Trans Co	46.977	29,093	34,579	32,394	42,937	27,893	32,558	33.697	28,056	28,198	51,313	33,310	421,005
00021	National Grid Trans Services	3,337	4,650	2,674	3,057	3,321	2,394	3,064	2,896	3,058	3,095	3,165	2,940	37,651
00035	Niagara Mohawk Holdings, Inc.	-	2,498	4,755	125	967	1,766	2,934	1,611	2,663	890	-	-	18,209
00036	Niagara Mohawk Power Corp	19,298,844	20.416,420	23,744,764	17,947,324	20,310.800	25.256,499	20,945,820	22,905.592	29,319,342	23,959,179	23,357,483	24,345,323	271,807,390
00037	Opinac North America, Inc	-	-	-	375	-	-	-	-	-	-	-	-	375
00041	Granite State Electric Company	738,290	602,491	630,547	516,997	525,457	526,990	530,420	572,158	671,540	612,641	563,644	715,629	7,206,804
00048	Narragansett Gas Company	2,295,379	1,820,069	2,187,313	2,021,855	2,016,867	2,698,284	2,062,017	2,077,009	3.028,557	3,027,709	2,904,268	3,360,731	29,500,058
00049	Narragansett Electric Company	5,971.371	5.456.510	7,190,775	5,509,424	6.362.983	6.393,441	5,968,918	5,905.298	8.043,788	6,618,133	5,536,359	5,973,271	74,930,270
00070	Wayfinder Group Inc.	2.679	(4,272)	2,322	404	573	3,903	1,556	817	2,245	618	2,989	3,056	16,890
00071	Valley Appliance & Merchandise	1,011	578	1,027	208	530	314	527	293	574	499	638	314	6,514
00072	National Grid Billing Entity	265,202	177,158	307,796	486,571	227,414	55,086	692,195	134,230	(43,370)	121,660	3,674,988	117,161	6,216,091
00076	NGrid Communications Billing	-	(67,303)	-	-	-	-	-	-	-	-	-	-	(67,303)
00082	GridAmerica Holdings	-	(43)	450	-	1,637	92	-	-	-	-	-	-	2,137
00085	NEES Energy, Inc.	1,075	110	2,016	564	633	474	566	561	560	575	571	568	8,272
00086	EUA Energy Investment	223	286	214	224	223	211	226	225	224	226	229	228	2,740
00092	Prudence Corporation	-	-	53	-	-	-	-	-	-	-	-	-	53
00093	Patience Corporation	-	270	53	-	-	-	-	-	-	-	2,168	-	2,490
00094	Newport America Corporation	-	216	53	-	-	-	-	-	-	-	-	-	268
00095	Metrowest Realty LLC	261	2,186	198	268	432	1,051	664	1.206	631	759	711	687	9,054
00402	Essex Gas Company	32	64	(22)	942	2,442	2,624	2,702	1,427	2,298	2,571	2,472	3,886	21,439
00457	KeySpan Energy Services Inc.	-	-	-	-	-	-	-	-	2,893	-	-	-	2,893
00460	KeySpan Corporation	-	-	-	249	-	-	-	7,017	27,284	121,483	777	-	156,810
01401	Boston Gas Company Billing BU	4,920.072	6.550,560	13,648,759	4,027,116	7,755.663	7.235,980	5,562,372	5,743.712	7.533,486	9,311,410	7,775,945	7,610.836	87,675,910
01402	ESSEX COUNTY GAS COMPANY	(2,114)	23,499	321,025	(14,210)	(2,356)	16,271	13,172	(9,352)	(1,112)	76,142	(12,481)	(29,850)	378,634
01403	Colonial Lowell Div Billing BU	1,025,469	1,453,842	3,248,545	827,611	1,675,465	1,515,951	1,135,563	1,344,442	1,590,457	1,657,889	1,343,759	1,677,193	18,496,186
01404	Colonial Cape Cod Billing BU	533	17,176	306,961	11,677	33,263	28,287	69,396	40.027	96,451	158,130	59,899	56,857	878,657
01406	EnergyNorth Nat Gas Billing BU	567.419	843.276	1,866,701	508.180	995,726	956.899	713,534	745.294	951,589	973,635	796.604	994,452	10,913,308
01407	KEYSPAN NEW ENGLAND LLC	15,439	8,386	9,110	13,917	5,931	5,771	6,490	2,594	6,344	32,428	6,298	11,744	124,449
01429	KEYSPAN MONEY POOLS	870,271	1,318,607	1,400,738	1,076,749	833,459	659,172	793,456	798,352	819,007	737,632	907,436	68,613	10,283,490
01431	KeySpan Corp Serv Billing BU	5.000	(5,702)	-	6,813	28.720	-	206	1.079	-	6,912	-	2,667	45,695
01434	KeySpan Electric Srv BillingBU	7,446.245	11.201,859	19.391,839	9,520,356	14,622.552	12.685,238	9,606,052	10,973,857	13.813,994	12,648,478	11,753,816	13,599,872	147,264,159
01435	KeySpan Generation Billing BU	3,456,792	4,869,680	7,697,016	4,718,706	7,966.550	6,976,346	4,912,387	4,985.035	6,582,629	4,451,372	4,313,088	4,845,004	65,774,605
01436	KeySpan Energy Dev Billing BU	194.453	313,394	614,336	281.815	428,755	350,092	453,354	367.763	441,385	406,172	321,320	495,501	4,668,341
01437	KS Gas East Corp KEDLI Bill BU	5,684.891	7,280,050	13,606,633	5,915,661	8,964.904	9.216,605	5,929,128	7,697.810	8.104,934	8,511,774	7.748.794	8,817.524	97,478,708
01438	Brklyn Union Gas KEDNY Bill BU	8,205,867	10,985,356	23,313,656	7,111,847	13,841,736	12.929,991	9,334,785	10,942,985	11,529,634	13,097,056	11,898,969	13,167,025	146,358,908
01441	TRANSCANADA RAVENSWOOD	-	-	-	35,674	-	-	-	-	-	-	-	-	35,674
01442	KS Ravenswood Srvcs Billing BU	1,709.358	2.805,293	5,443,459	1,677,847	3,577.019	2.983,547	2,189,277	2,339.783	121,041	125,234	187,599	77,317	23,236,775
01444	KS Energy Trading Billing BU	196,893	305.768	1,407,777	470.325	627.372	363,837	257,013	401.541	742,934	529,194	417,470	424,470	6,144,594
01446	KS Glenwood Energy Billing BU	134,588	110,807	185,965	134,450	265,122	348,130	170,745	241,219	269,404	254,964	255,544	174,756	2,545,695
01448	KS Port Jeff Energy Billing BU	110,098	146,108	255,123	376,571	246,936	179,623	269,207	239,606	183,893	261,275	205,914	213,213	2,687,566
01457	KEYSPAN ENERGY SERVICES INC.	17.026	33,324	82,720	36,466	51,817	35,550	23,532	39.380	15,572	13,423	13,605	22.035	384,450
01458	KS Energy Supply Billing BU	97.601	240.895	(335,730)	(1,049)	-	-	-	-	-	-	-	-	1,717
01459	KS Services Billing BU	595,449	940,737	1,791,951	1,132,523	1,182,231	1,357,602	1,038,894	1,329,376	1,927,826	1,222,247	1,130,351	1,494,304	15,143,491
01460	KEYSPAN ENERGY CORP	(1,598.356)	(1.823,420)	(1,858,392)	(1,827,667)	(1,788.485)	(1.735,306)	(1,876,333)	(1,302.045)	(1.542.953)	(1,812,375)	(1,828,767)	(1,664.483)	(20,658,581)
01471	Seneca Upshur Billing BU	40,924	81,917	171.979	52,090	157,849	139,222	99,070	150.518	138,655	98,819	90,136	155,148	1,376,326
82	NG RAVENSWOOD SERV (post Sale)	-	-	-	-	-	-	-	-	2,949,558	2.343,852	2,093,315	2,656,072	10,042,797
01563	KeySpan E&P JV Billing BU	3,278	7,913	16.252	(8,897)	3,378	557	1.110	960	1,499	656	1,357	1,059	29,121.
C4	KEYSPAN LNG LP REGULATED ENTITY	(3.177)	-	-	-	-	-	-	-	-	-	-	-	(3,177)
NK	NGUSA Service Company, Inc.	-	-	-	-	-	-	-	-	-	-	-	1,556	1,556
Total		82,300,317	95,840,024	155,001,185	81,795,724	113,427,527	112,991,437	91,460,296	98,916,101	124,546,678	112,629,452	106,833,511	115,225,208	1,290,967,461

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2009 Amounts Charged from NGRID USA Service Co. to Affiliates by Month

	Charged Company	January 2009	February 2009	March 2009	April 2009	May 2009	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	
00001	National Grid USA	635,699	245,814	536,252	215,416	242,457	265,401	189,058	201,959	720,522	145,127	283,831	336,193	4,017,730
00004	Nantucket Electric Company	134,739	149.514	285,553	127,269	138,916	207,424	126,434	143,260	180,213	178,477	168,732	184.037	2,024,569
00005	Massachusetts Electric Company	21,154,620	32.979.716	29.822.206	15.112.861	17,277,532	20,859.456	14,543.630	16.148,570	18,682,889	17,528,908	16,881.826	17.731.232	238,723,445
00006	NE Hydro - Trans Electric Co	249,605	267,916	319,305	273,185	291,797	283,933	273,809	245,324	271,746	310,045	375,328	324,409	3,486,402
00007	New England Hydro Finance Co	-	-	-	-	-	1	(1)	-	355	(512)	126	-	(31)
00008	New England Hydro - Trans Corp	54,040	68,634	82,192	82,296	81,345	127,483	65,630	90,943	99,740	128,082	76,321	93,152	1,049,859
00010	New England Power Company	4,279,713	4,816.696	7,916,029	4,370,829	3,654,234	5,385,562	4,024,357	4,270,045	6,015,053	5,406,124	4,626,325	5,266,943	60,031,910
00020	New England Electric Trans Co	32,814	26,685	41,336	15,276	17,093	24,351	38,885	151,134	197.827	90,973	160,465	(1,457.510)	(660,671)
00021	National Grid Trans Services	(1,194)	3,084	2,767	6,386	3,214	3,257	3,038	3,473	3,226	3,086	3,228	3,332	36,895
00035	Niagara Mohawk Holdings, Inc.	-	-	-	120	-	4	(4)	-	-	-	19,029	24,258	43,407
00036	Niagara Mohawk Power Corp	24,872,163	39,431.018	44,974,165	19,406,146	22,647,312	34,216,906	22,793,492	24,688,997	34,316,128	26,130,971	26.155.391	29.837,162	349,469,851
00037	Opinac North America, Inc	-	-	-	-	-	8	(8)	-	-	-	-	-	-
00041	Granite State Electric Company	882,874	808.694	964,539	531,859	594,717	640,177	486,954	530,347	638,570	595,837	591,585	653.888	7,920,041
00048	Narragansett Gas Company	1.313,540	2,443.061	4,618,536	2,224,737	2,731,805	3,310.212	2,721,608	3,451,685	3,387,787	3.815,309	2.929.998	3,776.196	36,724,474
00049	Narragansett Electric Company	5,675,841	8,430.154	9,888,835	5,073,870	5,818,926	7,817,519	5,220,369	5,727,760	6,871,496	6,528,804	5,968,968	6,823,007	79,845,549
00070	Wayfinder Group Inc.	27,163	1,594	5,581	10,119	2,368	2.922	1,774	2,523	2,435	(751)	1,676	1,558	58,962
00071	Valley Appliance & Merchandise	(2,151)	1,012	445	1,590	300	(36)	100	101	99	(273)	12	9	1,207
00072	National Grid Billing Entity	63,097	219,983	1,945,740	507,533	131,245	398,733	211,438	137,672	507,810	582,625	131,878	154,131	4,991,884
00082	GridAmerica Holdings	597	100	61,844	895	200	246	200	267	200	(131)	100	100	64,617
00083	GridAmerica LLC	-	-	-	-	-	-	140	-	-	-	(140)	-	-
00085	NEES Energy, Inc.	1,118	671	957	1,754	748	753	1,033	3,455	766	732	746	744	13,477
00086	EUA Energy Investment	871	330	325	1.218	425	424	427	436	435	453	424	424	6,191
00092	Prudence Corporation	139	-	-	12	16	17	12	14	14	14	14	14	268
00093	Patience Corporation	139	-	-	-	-	1	140	67	-	-	-	-	347
00094	Newport America Corporation	595	-	-	-	-	2	-	299	-	-	-	-	896
00095	Metrowest Realty LLC	2,256	921	837	1,154	504	523	626	505	2,020	3,700	2,693	4,568	20,306
00402	Essex Gas Company	9.577	1,404	6,227	4,727	8,033	4,364	3,789	4,225	5,879	5,308	5.153	31,394	90,082
00460	KeySpan Corporation	-	-	-	-	-	-	1,806	-	-	-	-	-	1,806
01401	Boston Gas Company Billing BU	5,526,725	8,299,018	11,688,021	5,728,094	7,274,338	8,188,715	5,066,775	9,020,038	8,129,125	6,066,682	6,115,545	9,000,245	90,103,320
01402	ESSEX COUNTY GAS COMPANY	(111,493)	(13.670)	(25,294)	(8,271)	21,223	27,630	16,711	15,357	15,539	274,164	222,334	415.951	850,180
01403	Colonial Lowell Div Billing BU	1,113,056	1,561,988	2,423,650	1,248,714	1,478,503	1,818,410	1,077,727	1,861,416	1,839,938	1,310,924	1,399,838	1,852,278	18,986,444
01404	Colonial Cape Cod Billing BU	(205,468)	45,725	6,152	5,746	18,776	70,822	73,859	95,192	29,509	112,341	107,336	144,504	504,494
01406	EnergyNorth Nat Gas Billing BU	492,346	912.946	1,266.111	655,721	829,724	1.065,712	667,801	1,141,854	967,817	666,661	871,600	1,351.325	10,889,618
01407	KEYSPAN NEW ENGLAND LLC	16,888	54,216	35,582	16,258	8,717	14,295	18,590	17,397	5,918	7,343	29,300	43,566	268,070
01429	KEYSPAN MONEY POOLS	326,452	303.562	73,426	225,092	154,574	148,455	269,377	225,446	205,623	187,875	400,695	486.215	3,006,793
01431	KeySpan Corp Serv Billing BU	13,811	17.182	(234,312)	77.202	29,486	18,755	10,286	20,599	9,097	8,994	11,255	54,871	37,226
01434	KeySpan Electric Srv BillingBU	10,276,942	13,182,174	19,103,491	11,584,492	12,266,054	14,640,959	10,029,750	12,590,513	13,751,189	11,730,625	11,183,610	13,793,165	154,132,965
01435	KeySpan Generation Billing BU	3,309,639	5,488.044	9,164,484	7,118,871	7,537,030	8,548,874	6,048,605	5,858,827	6,677,980	6,281,588	5,485,491	5,901.237	77,420,670
01436	KeySpan Energy Dev Billing BU	264,749	529.927	1,163,117	307,495	331,508	390,688	236,739	406,869	541,429	249.796	233,235	374.645	5,030,199
01437	KS Gas East Corp KEDLI Bill BU	6,389,064	8,465,942	12,554,297	6,603,947	7,443,472	9,041,912	5,971,219	8,044,873	8,734,493	7,404,371	6,943,384	8,348,524	95,945,499
01438	Brklyn Union Gas KEDNY Bill BU	10,092,820	13,941,708	21,397,198	10,600.055	11,308,135	13,898.622	10.135.839	12,662,856	15,551,391	11,150,208	10,519,222	12.265,675	153,523,730
01442	KS Ravenswood Srvcs Billing BU	96,970	271,458	337,805	-	-	-	133	-	-	-	-	-	706,366
01444	KS Energy Trading Billing BU	266,110	329,195	490,133	404,104	378,316	393,474	221,851	426,327	278,606	225,814	198,384	286,614	3,898,926
01446	KS Glenwood Energy Billing BU	118,383	149.676	257,353	314,930	279,331	183,615	246,087	173,132	204,043	258,796	165,245	198.507	2,549,096
01448	KS Port Jeff Energy Billing BU	121,840	153,663	303,853	324,296	226,076	285,196	301,532	197.738	287,721	175,584	161,948	214.478	2,753,923
01457	KEYSPAN ENERGY SERVICES INC.	-	-	(334)	-	-	-	-	-	-	-	-	-	(334)
01458	KS Energy Supply Billing BU	-	22	-	-	-	-	4	-	-	-	-	-	25
01459	KS Services Billing BU	961,669	940,666	2,086,999	817,670	865,339	889,729	635,127	880,120	1,122,932	803,893	839,505	1,210,204	12,053,853
01460	KEYSPAN ENERGY CORP	(1,501,502)	(1,866.830)	71,665	(2,485,854)	(1,783,228)	(1,833,060)	(1,603,141)	(1,719,169)	(1,831,452)	(1,825,614)	(1,892,765)	(1.800,836)	(20,071,787)
01471	Seneca Upshur Billing BU	80,555	92.941	260.477	44.951	54,015	82.569	43,360	60.199	74.235	49.532	50.718	84.937	978,489
82	NG RAVENSWOOD SERV (post Sale)	1,584,246	2,030,069	3,442,668	10,312	3.867	(14,313)	(8,123)	(13,690)	(1,084,102)	-	-	-	5,950,934
01563	KeySpan E&P JV Billing BU	1,075	4,513	6,667	1,563	2,249	5,667	2,293	2,790	3,759	2,753	2.345	3,609	39,283
DI	TRANSGAS	-	-	6,685	-	-	-	-	-	-	-	-	-	6,685
NK	NGUSA Service Company, Inc.	(1,556)	1,556	(1,556)	1,556	-	-	-	-	-	-	-	-	-
Total		$98,621,174	$144,792,693	$187,352,007	$91,566,198	$102,370,693	$131,416,371	$90,171,138	$107,771,743	$127,420,001	$106,595,237	$101,431,934	$118,018,952	$1,407,528,141

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Annual Amounts Charged from NGRID USA Service Co. to Affiliates

	Charged Company	2006	2007	2008	2009	
00001	National Grid USA	$6,892,894	$7,199,114	$8,994,548	$3,861,314	$26,947,870
00004	Nantucket Electric Company	2,120,106	1,886,808	1,839,537	1,671,033	7,517,485
00005	Massachusetts Electric Company	156,715,567	165,020,634	195,096,973	221,847,141	738,680,315
00006	NE Hydro - Trans Electric Co	3,208,133	3,307,713	3,596,249	3,364,572	13,476,667
00007	New England Hydro Finance Co	-	109	443	(31)	521
00008	New England Hydro - Trans Corp	1,060,162	1,202,494	923,284	955,674	4,141,613
00010	New England Power Company	42,417,423	44,200,296	50,368,270	57,618,030	194,604,019
00020	New England Electric Trans Co	837,531	592,229	415,442	(667,931)	1,177,271
00021	National Grid Trans Services	7,302	115,682	37,651	36,895	197,530
00035	Niagara Mohawk Holdings, Inc.	859	7,572	18,209	43,407	70,047
00036	Niagara Mohawk Power Corp	192,708,260	229,480,143	255,504,904	306,215,399	983,908,705
00037	Opinac North America, Inc	3,298	3,911	375	-	7,584
00041	Granite State Electric Company	5,365,037	6,523,354	6,903,182	7,085,600	25,877,172
00048	Narragansett Gas Company	5,828,034	21,157,400	24,453,798	28,248,718	79,687,950
00049	Narragansett Electric Company	59,287,685	63,057,791	72,222,417	72,923,948	267,491,841
00070	Wayfinder Gronp Inc.	9,144	12,518	16,890	58,962	97,514
00071	Valley Appliance & Merchandise	737	6,623	6,514	1,207	15,081
00072	National Grid Billing Entity	4,523,622	4,651,381	6,216,091	4,991,884	20,382,978
00075	NEES Communications, Inc.	301	-	-	-	301
00076	NGrid Communications Billing	2,304,578	1,692,712	(67,303)	-	3,929,988
00077	Grid Communications Inc	225	-	-	-	225
00078	Atlantic Western Consulting	160	-	-	-	160
00079	National Grid Wireless Cons	(2,957)	1,593	-	-	(1,363)
00082	GridAmerica Holdings	(9,147)	43,816	2,137	64,617	101,423
00083	GridAmerica LLC	124,056	-	-	-	124,056
00085	NEES Energy, Inc.	10,732	8,258	8,272	13,477	40,739
00086	EUA Energy Investment	2,418	2,472	2,740	6,191	13,820
00092	Prudence Corporation	515	211	53	268	1,046
00093	Patience Corporation	20	208	2,490	347	3,065
00094	Newport America Corporation	242	601	268	896	2,006
00095	Metrowest Realty LLC	1,581	2,549	9,054	20,306	33,490
00402	Essex Gas Company	-	-	21,439	90,082	111,521
00457	KeySpan Energy Services Inc.	-	-	2,893	-	2,893
00460	KeySpan Corporation	-	-	156,810	1,806	158,617
01401	Boston Gas Company Billing BU	-	14,264	3,993,110	15,473,256	19,480,629
01403	Colonial Lowell Div Billing BU	-	2,821	723,647	2,620,983	3,347,450
01404	Colonial Cape Cod Billing BU	-	2,305	63,487	113,471	179,263
01406	EnergyNorth Nat Gas Billing BU	-	1,515	488,424	1,667,747	2,157,686
01431	KeySpan Corp Serv Billing BU	-	423	45,695	37,226	83,345
01434	KeySpan Electric Srv BillingBU	-	14,206	5,739,371	14,405,163	20,158,739
01435	KeySpan Generation Billing BU	-	3,659	1,802,621	5,190,952	6,997,232
01436	KeySpan Energy Dev Billing BU	-	47	23,191	46,644	69,882
01437	KS Gas East Corp KEDLI Bill BU	-	9,459	2,627,915	9,642,723	12,280,098
01438	Brklyn Union Gas KEDNY Bill BU	-	21,296	5,231,141	20,909,732	26,162,169
01442	KS Ravenswood Srvcs Billing BU	-	2,658	998,370	706,366	1,707,394
01444	KS Energy Trading Billing BU	-	17	3,518	5,539	9,074
01446	KS Glenwood Energy Billing BU	-	90	48,412	107,582	156,084
01448	KS Port Jeff Energy Billing BU	-	86	38,962	98,266	137,314
01458	KS Energy Supply Billing BU	-	11	1,717	25	1,753
01459	KS Services Billing BU	-	753	1,354,028	298,710	1,653,491
01471	Seneca Upshur Billing BU	-	272	127,417	285,942	413,632
01563	KeySpan E&P JV Billing BU	-	39	14,270	28,823	43,132
	Total Charged from NGRID USA Service Co.	$483,418,520	$550,252,109	$650,078,922	$780,092,965	$2,463,842,516

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Annual Amounts Charged from KeySpan Service Companies to Affiliates

	Charged Company	SEP - DEC 2007	2008	2009	
01	BOSTON GAS COMPANY	25,622,885	83,682,801	74,630,065	183,935,750
02	ESSEX COUNTY GAS COMPANY	64,904	378,634	850,180	1,293,719
03	Colonial Lowell Division	5,514,024	17,772,540	16,365,461	39,652,025
04	Colonial Cape Cod Div	154,690	815,170	391,023	1,360,882
06	EnergyNorth Company	3,109,930	10,424,884	9,221,871	22,756,685
07	KEYSPAN NEW ENGLAND LLC	55,803	124,449	268,070	448,322
29	KEYSPAN MONEY POOLS	4,656,100	10,283,490	3,006,793	17,946,383
34	KEYSPAN ELECTRIC SERVICES, LLC	41,456,727	141,524,788	139,727,803	322,709,317
35	KEYSPAN GENERATION SERVICES,LLC	18,391,493	63,971,984	72,229,717	154,593,194
36	KEYSPAN ENERGY DEVELOPMENT	1,500,371	4,645,150	4,983,555	11,129,076
37	KEYSPAN ENERGY DELIVERY LI	27,654,523	94,850,792	86,302,775	208,808,091
38	KEYSPAN ENERGY DELIVERY NY	40,612,623	141,127,768	132,613,998	314,354,389
41	TRANSCANADA RAVENSWOOD	-	35,674	-	35,674
42	TRANSCANADA RAV SERVICES	10,459,683	22,238,406	-	32,698,089
44	KEYSPAN ENERGY TRADING SERVICES, LLC	1,367,519	6,141,076	3,893,387	11,401,983
46	KEYSPAN GLENWOOD ENERGY CENTER LLC	535,994	2,497,283	2,441,514	5,474,791
47	KEYSPAN SPAGNOLI ROAD ENERGY CENTER LLC	-	-	-	-
48	KEYSPAN PORT JEFFERSON ENERGY CENTER LLC	822,436	2,648,604	2,655,657	6,126,696
57	KEYSPAN ENERGY SERVICES INC.	183,645	384,450	(334)	567,761
58	KEYSPAN ENERGY SUPPLY INC.	1,041,088	-	-	1,041,088
59	KEYSPAN SERVICES INC	3,799,032	13,789,463	11,755,144	29,343,639
60	KEYSPAN ENERGY CORP	(7,615,531)	(20,658,581)	(20,071,787)	(48,345,900)
71	SENECA UPSHUR PETROLEUM	187,621	1,248,909	692,546	2,129,076
82	NG RAVENSWOOD SERV (post Sale)	-	10,042,797	5,950,934	15,993,732
C4	KEYSPAN LNG LP REGULATED ENTITY	-	(3,177)	-	(3,177)
D1	TRANSGAS	-	-	6,685	6,685
F1	KEYSPAN E&P JOINT VENTURE 50%	10,966	14,851	10,460	36,277
KT	KEYSPAN TECHNOLOGIES	-	-	-	-
NA	National Grid USA (Parent)	7,913	84,297	156,416	248,626
NB	Nantucket Electric Company	5,389	146,028	353,535	504,952
NC	Massachusetts Electric Company	309,794	7,130,862	16,876,303	24,316,960
ND	New England Power Company	33,835	1,075,902	2,413,879	3,523,616
NE	Niagara Mohawk Power-Elect Dist	735,154	12,819,059	26,664,409	40,218,623
NF	Granite State Electric Company	10,736	303,623	834,441	1,148,800
NG	Narragansett Gas Company	82,545	5,046,260	8,475,756	13,604,561
NH	Narragansett Electric Company	140,346	2,707,853	6,921,601	9,769,800
NK	NGUSA Service Company, Inc.	-	1,556	-	1,556
NL	NE Hydro-Trans Elec Co, Inc.	3,500	54,806	121,830	180,136
NN	NE Hydro-Trans Corporation	3,044	47,098	94,185	144,327
NO	NE Electric Trans Corporation	456	5,564	7,260	13,280
NP	Niagara Mohawk Power-Gas	-	2,929,055	14,255,528	17,184,584
NQ	Niagara Mohawk Power-Trans	-	554,372	2,334,514	2,888,886
Grand Total		180,919,238	640,888,539	627,435,176	1,449,242,953

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2006 Amounts Charged from NGRID USA Service Co. to Affiliates by Month

	Charged Company	January 2006	February 2006	March 2006	April 2006	May 2006	June 2006	July 2006	August 2006	September 2006	October 2006	November 2006	December 2006	
00001	National Grid USA	$406,324	$381,815	$2,417,722	$383,781	$546,688	$328,368	$264,368	$414,103	$435,979	$332,907	$344,056	$636,783	$6,892,894
00004	Nantucket Electric Company	144,269	150,313	205,773	161,335	192,839	216,836	171,892	257,639	152,392	173,634	162,867	130,316	2,120,106
00005	Massachusetts Electric Company	12.432,906	12,365.011	16,779,554	10,859,274	11,435,816	14,579,261	12,056,245	12,584,040	13,842,246	13,711,945	12.565,592	13,503,678	156,715,567
00006	NE Hydro - Trans Electric Co	250,737	246,494	295,195	288,260	255,470	251,562	261,695	237,577	261,945	308,074	272,342	278,784	3,208,133
00007	New England Hydro Finance Co	-	-	-	102	-	(102)	-	-	-	-	-	-	-
00008	New England Hydro - Trans Corp	77,421	55,650	181,745	120,362	56,581	73,820	114,182	79,879	63,575	87,740	68,280	80,927	1,060,162
00010	New England Power Company	3,762,216	3,505,636	4,505,331	3,288,712	3,131,594	3,637,966	3,284,776	3,742,823	3.229,922	3,428,763	3,558,392	3,341,293	42,417,423
00020	New England Electric Trans Co	50,609	57.342	65,552	102,844	75,740	64.722	75,283	62,603	56,961	98,448	65,085	62,342	837,531
00021	National Grid Trans Services	138	117	1,601	590	591	631	751	569	484	637	584	609	7,302
00035	Niagara Mohawk Holdings, Inc.	-	-	9	-	-	-	-	-	138	296	416	-	859
00036	Niagara Mohawk Power Corp	16,611,944	13,956,090	13,735,099	12,800,442	14,372,174	15,412,970	16,031,225	14,996,347	16,066,770	20,103,242	20,293,489	18,328,468	192,708,260
00037	Opinac North America, Inc	-	-	1,544	-	1,390	109	-	-	-	255	-	-	3,298
00041	Granite State Electric Company	453,665	427.982	549,632	447.791	413,909	461,141	399,262	441,821	453,156	460,355	422,366	433,957	5,365,037
00048	Narragansett Gas Company	-	-	-	-	-	-	-	7,773	1,247,535	1,751,462	1,250,248	1,571,017	5,828,034
00049	Narragansett Electric Company	4,660,564	4,695,614	5,665,534	4,039,097	4,471,798	5,269,656	4,932.481	5,104,422	5,437,030	5,367,167	4,706,054	4,938,269	59,287,685
00070	Wayfinder Group Inc.	311	221	1,698	1,677	644	1,004	885	700	738	707	637	(78)	9,144
00071	Valley Appliance & Merchandise	-	-	-	-	-	-	-	-	20	717	-	-	737
00072	National Grid Billing Entity	291,215	75,262	342,155	542,616	353,520	703,669	553,620	369,865	266,936	142,780	378,992	502,989	4,523,622
00075	NEES Communications, Inc.	301	-	-	-	-	-	-	-	-	-	-	-	301
00076	NGrid Communications Billing	337.420	138.085	175,722	226,695	200,564	(19,535)	200,497	224,338	216,784	221,836	214,734	167,440	2,304,578
00077	Grid Communications Inc	222	-	3	-	-	-	-	-	-	-	-	-	225
00078	Atlantic Western Consulting	158	-	2	-	-	-	-	-	-	-	-	-	160
00079	National Grid Wireless Cons	-	(3,207)	31	300	-	-	-	(80)	-	-	-	-	(2,957)
00082	GridAmerica Holdings	461	(177)	(7,501)	40,013	4,390	(14,518)	(2,858)	(4,111)	(10,677)	(11,872)	(698)	(1,600)	(9,147)
00083	GridAmerica LLC	111,191	3,948	8,917	-	-	-	-	-	-	-	-	-	124,056
00085	NEES Energy, Inc.	217	351	2,969	876	574	729	554	513	2,377	595	580	398	10,732
00086	EUA Energy Investment	26	15	1,222	429	149	476	(295)	151	195	290	178	(418)	2,418
00092	Prudence Corporation	-	-	-	-	-	-	-	-	20	495	-	-	515
00093	Patience Corporation	-	-	-	-	-	-	-	-	20	-	-	-	20
00094	Newport America Corporation	-	-	-	-	-	-	-	-	20	222	-	-	242
00095	Metrowest Realty LLC	40	44	476	151	151	151	(126)	151	218	197	192	(63)	1,581
	Total Charged from NGRID USA Service Co.	$39,592,355	$36,056,606	$44,929,984	$33,305,346	$35,514,584	$40,968,916	$38,344,435	$38,521,121	$41,724,783	$46,180,893	$44,304,387	$43,975,110	$483,418,520

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2007 Amounts Charged from NGRID USA Service Co. to Affiliates by Month

	Charged Company	January 2007	February 2007	March 2007	April 2007	May 2007	June 2007	July 2007	August 2007	September 2007	October 2007	November 2007	December 2007	
00001	National Grid USA	$401,048	$401,692	$699,572	$409,886	$418,881	$427.064	$458.700	$1,260.687	$427,553	$762.296	$465,398	$1,066,337	$7,199,114
00004	Nantucket Electric Company	186.506	177,075	293,682	105,626	131,332	123.695	137,321	204,723	113,100	128,639	142.167	142,941	1,886,808
00005	Massachusetts Electric Company	12.254,659	12,734,934	19,600.885	10.796.235	13.211,714	13,912,576	13.239,891	14,404.977	12,925.708	14,248.587	13.964,108	13,726.360	165,020,634
00006	NE Hydro - Trans Electric Co	311,949	245,638	342,911	264,203	258,341	386,425	269,199	260,746	228,395	251,745	294,290	193,870	3,307,713
00007	New England Hydro Finance Co	-	-	-	-	-	-	109	-	-	-	-	-	109
00008	New England Hydro - Trans Corp	85,370	84,528	161,363	149,349	72,919	94,238	71,714	105,320	65,472	149,723	90,987	71,511	1,202,494
00010	New England Power Company	3,219,663	3,454,978	4,815,187	3,024,044	3,403,562	3,404,226	3,579,362	4,019,837	4,113,053	3,579,510	4,073,375	3,513,500	44,200,296
00020	New England Electric Trans Co	68,340	57,788	65,689	59,297	46,970	52,858	33,487	39,695	39,210	41,847	52,184	34,864	592,229
00021	National Grid Trans Services	545	462	336	401	357	427	1,188	123,625	(20,269)	2,202	3,547	2,861	115,682
00035	Niagara Mohawk Holdings, Inc.	-	-	-	-	-	-	-	-	-	-	-	7,572	7,572
00036	Niagara Mohawk Power Corp	19,218,946	18,380,328	21,978.954	13.746,287	18,689,214	16,479,492	19,806,665	21,422,162	19,370.108	21,130,748	19.002,112	20,255.124	229,480,143
00037	Oplnac North America, Inc	-	5	667	-	1,860	-	1,380	-	-	-	-	-	3,911
00041	Granite State Electric Company	457,432	403,645	753,213	439,172	471,606	889,492	440,833	563,014	405,191	592.446	601,928	505.382	6,523,354
00048	Narragansett Gas Company	1,562,086	1,445,889	2.012,064	1,371,306	1,396,912	1,794,893	1,628,565	2,109.684	1,561,678	2,699,704	1.848,739	1,725.880	21,157,400
00049	Narragansett Electric Company	4,980,156	4,820,678	7,487,973	4,092,107	4,964,642	5,123,707	4,962,673	5,352,535	5,104,066	5,146,994	5,703,931	5,318,329	63,057,791
00070	Wayfinder Group Inc.	1,505	714	2,072	858	696	690	(83)	641	(124)	411	1,437	3,702	12,518
00071	Valley Appliance & Merchandise	50		504	304	380	1,101	368	464	782	413	375	1,880	6,623
00072	National Grid Billing Entity	228,523	386,954	265,160	348,446	312,855	399,138	299,493	340,843	391,597	351,317	587,289	739,766	4,651,381
00076	NGrid Communications Billing	203,053	188.159	207,428	226,407	269,026	212.448	198,190	117,181	2,940	68,021	(139)	-	1,692,712
00079	National Grid Wireless Cons	1,593	-	-	-	-	-	-	-	-	-	-	-	1,593
00082	GridAmerica Holdings	2,002	1,825	29,911	2,064	3,013	4,940	14,858	-	-	(14,797)	-	-	43,816
00085	NEES Energy, Inc.	778	1,604	493	614	706	570	316	564	551	866	650	545	8,258
00086	EUA Energy Investment	176	354	(248)	434	173	174	264	223	216	222	267	217	2,472
00092	Prudence Corporation	50	-	161	-	-	-	-	-	-	-	-	-	211
00093	Patience Corporation	50	-	158	-	-	-	-	-	-	-	-	-	208
00094	Newport America Corporation	50	-	106	-	444	-	-	-	-	-	-	-	601
00095	Metrowest Realty LLC	189	182	(1)	344	359	415	(500)	240	199	270	670	182	2,549
01401	Boston Gas Company Billing BU	-	-	-	-	-	-	-	-	-	-	296	13,968	14,264
01403	Colonial Lowell Div Billing BU	-	-	-	-	-	-	-	-	-	-	59	2,762	2,821
01404	Colonial Cape Cod Billing BU	-	-	-	-	-	-	-	-	-	-		2,305	2,305
01406	EnergyNorth Nat Gas Billing BU	-	-	-	-	-	-	-	-	-	-	32	1,484	1,515
01431	KeySpan Corp Serv Billing BU	-	-	-	-	-	-	-	-	-	-		423	423
01434	KeySpan Electric Srv BillingBU	-	-	-	-	-	-	-	-	-	-	346	13.860	14,206
01435	KeySpan Generation Billing BU	-	-	-	-	-	-	-	-	-	-	152	3,507	3,659
01436	KeySpan Energy Dev Billing BU	-	-	-	-	-	-	-	-	-	-	0	47	47
01437	KS Gas East Corp KEDLI Bill BU	-	-	-	-	-	-	-	-	-	-	198	9,261	9,459
01438	Brklyn Union Gas KEDNY Bill BU	-	-	-	-	-	-	-	-	-	-	444	20,852	21,296
01442	KS Ravenswood Srvcs Billing BU	-	-	-	-	-	-	-	-	-	-	115	2,543	2,658
01444	KS Energy Trading Billing BU	-	-	-	-	-	-	-	-	-	-	0	17	17
01446	KS Glenwood Energy Billing BU	-	-	-	-	-	-	-	-	-	-	4	86	90
01448	KS Port Jeff Energy Billing BU	-	-	-	-	-	-	-	-	-	-	4	82	86
01458	KS Energy Supply Billing BU	-	-	-	-	-	-	-	-	-	-	0	11	11
01459	KS Services Billing BU	-	-	-	-	-	-	-	-	-	-	18	736	753
01471	Seneca Upshur Billing BU	-	-	-	-	-	-	-	-	-	-	2	270	272
01563	KeySpan E&P JV Billing BU	-	-	-	-	-	-	-	-	-	-	-	39	39
	Total Charged from NGRID USA Service Co.	$43,184,719	$42,787,433	$58,718,240	$35,037,385	$43,655,962	$43,308,567	$45,143,993	$50,327,161	$44,729,427	$49,141,164	$46,834,984	$47,383,074	$550,252,109

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
For the Post Merger period August 27 (September 1) - December 31,Calendar Year 2007 Amounts Charged from KeySpan Service Companies to Affiliates by Month

	Charged Company	SEPTEMBER-07	OCTOBER-07	NOVEMBER-07	DECEMBER-07	
01	BOSTON GAS COMPANY	8,245,067	4,791,378	6,310,668	6,275,772	25,622,885
02	ESSEX COUNTY GAS COMPANY	26,963	(3,546)	27,784	13,703	64,904
03	Colonial Lowell Division	1,804,875	1,052,422	1,354,497	1,302,231	5,514,024
04	Colonial Cape Cod Div	59,784	25,967	47,802	21,137	154,690
05	COLONIAL ADMINISTRATION	-	-	-	-	-
06	EnergyNorth Company	1,030,861	583,544	787,125	708,401	3,109,930
07	KEYSPAN NEW ENGLAND LLC	37,795	479	9,912	7,617	55,803
29	KEYSPAN MONEY POOLS	1,799,915	1,254,063	887,210	714,913	4,656,100
34	KEYSPAN ELECTRIC SERVICES, LLC	12,247,825	8,315,566	9,848,393	11,044,942	41,456,727
35	KEYSPAN GENERATION SERVICES,LLC	6,022,513	3,742,309	3,777,342	4,849,329	18,391,493
36	KEYSPAN ENERGY DEVELOPMENT	653,624	78,249	325,791	442,708	1,500,371
37	KEYSPAN ENERGY DELIVERY LI	7,893,159	6,042,699	6,418,857	7,299,808	27,654,523
38	KEYSPAN ENERGY DELIVERY NY	11,749,295	8,267,717	9,857,006	10,738,605	40,612,623
41	TRANSCANADA RAVENSWOOD	-	-	-	-	-
42	TRANSCANADA RAV SERVICES	3,275,009	1,956,005	2,564,015	2,664,654	10,459,683
44	KEYSPAN ENERGY TRADING SERVICES, LLC	463,496	172,093	322,822	409,107	1,367,519
46	KEYSPAN GLENWOOD ENERGY CENTER LLC	250,202	16,643	121,276	147,874	535,994
47	KEYSPAN SPAGNOLI ROAD ENERGY CENTER LLC	-	-	-	-	-
48	KEYSPAN PORT JEFFERSON ENERGY CENTER LLC	203,510	324,887	142,012	152,027	822,436
57	KEYSPAN ENERGY SERVICES INC.	59,657	34,447	36,007	53,534	183,645
58	KEYSPAN ENERGY SUPPLY INC.	429,328	74,006	214,942	322,812	1,041,088
59	KEYSPAN SERVICES INC	1,135,720	905,464	917,947	839,901	3,799,032
60	KEYSPAN ENERGY CORP	(2,149,166)	(1,880,149)	(1,824,986)	(1,761,230)	(7,615,531)
71	SENECA UPSHUR PETROLEUM	75,661	15,447	50,856	45,658	187,621
82	NG RAVENSWOOD SERV (post Sale)	-	-	-	-	-
C4	KEYSPAN LNG LP REGULATED ENTITY	-	-	-	-	-
D1	TRANSGAS	-	-	-	-	-
F1	KEYSPAN E&P JOINT VENTURE 50%	5,354	(205)	3,253	2,565	10,966
KT	KEYSPAN TECHNOLOGIES	-	-	-	-	-
NA	National Grid USA (Parent)	-	-	3,665	4,248	7,913
NB	Nantucket Electric Company	-	-	2,529	2,860	5,389
NC	Massachusetts Electric Company	-	-	147,590	162,203	309,794
ND	New England Power Company	-	-	15,577	18,259	33,835
NE	Niagara Mohawk Power-Elect Dist	-	-	340,605	394,549	735,154
NF	Granite State Electric Company	-	-	5,123	5,613	10,736
NG	Narragansett Gas Company	-	-	28,608	53,937	82,545
NH	Narragansett Electric Company	-	-	62,396	77,949	140,346
NK	NGUSA Service Company, Inc.	-	-	-	-	-
NL	NE Hydro-Trans Elec Co, Inc.	-	-	1,621	1,879	3,500
NN	NE Hydro-Trans Corporation	-	-	1,410	1,634	3,044
NO	NE Electric Trans Corporation	-	-	211	245	456
NP	Niagara Mohawk Power-Gas	-	-	-	-	-
NQ	Niagara Mohawk Power-Trans	-	-	-	-	-
Grand Total		55,320,444	35,769,484	42,809,867	47,019,442	180,919,238

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2008 Amounts Charged from NGRID USA Service Co. to Affiliates by Month

	Charged Company	January 2008	February 2008	March 2008	April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	
00001	National Grid USA	$835,537	$916,401	$3,355,996	$189,186	$858,442	$486,773	$401,799	$341,871	$531,212	$310,072	$225,507	$541,752	$8,994,548
00004	Nantucket Electric Company	172,365	252,749	139,829	165,539	155,195	156,616	130,954	102,250	188,502	153,916	119,125	102,498	1,839,537
00005	Massachusetts Electric Company	14,285,765	14,201,040	18,833,925	14,405,706	16,189,022	16,037,113	15,437,754	14,562,570	19,841,025	16,896,130	15,030,450	19,376,472	195,096,973
00006	NE Hydro - Trans Electric Co	279,137	253,189	207,438	259,597	361,856	309,532	378,357	250,120	244,239	516,165	266,677	269,942	3,596,249
00007	New England Hydro Finance Co	-	-	102	-	-	-	-	341	-	-	-	-	443
00008	New England Hydro - Trans Corp	152,440	45,552	155,317	57,327	62,828	77,217	55,192	47,438	113,649	57,847	58,695	39,782	923,284
00010	New England Power Company	4,151,005	3,705,246	4,994,511	3,623,385	4,305,520	3,972,638	3,721,803	3,664,320	5,232,889	4,334,967	4,570,129	4,091,857	50,368,270
00020	New England Electric Trans Co	46,847	28,804	33,720	31,981	42,515	27,404	32,395	32,517	27,550	28,044	50,833	32,831	415,442
00021	National Grid Trans Services	3,337	4,650	2,674	3,057	3,321	2,394	3,064	2,896	3,058	3,095	3,165	2,940	37,651
00035	Niagara Mohawk Holdings, Inc.	-	2,498	4,755	125	967	1,766	2,934	1,611	2,663	890	-	-	18,209
00036	Niagara Mohawk Power Corp	19,090,843	19,816,504	22,444,420	16,954,262	19,185,703	23,771,039	20,116,069	20,498,741	27,578,248	22,167,431	21,388,695	22,492,949	255,504,904
00037	Opinac North America, Inc	-	-	-	375	-	-	-	-	-	-	-	-	375
00041	Granite State Electric Company	735,166	592,943	612,941	502,367	510,511	505,292	516,772	531,615	625,149	580,699	516,444	673,283	6,903,182
00048	Narragansett Gas Company	2,184,565	1,748,874	1,956,351	1,826,433	1,690,333	2,233,762	1,810,796	1,560,404	2,703,154	2,037,544	1,922,266	2,779,316	24,453,798
00049	Narragansett Electric Company	5,933,306	5,340,951	6,984,215	5,346,300	6,034,340	6,179,237	5,838,196	5,516,438	7,762,220	6,368,470	5,220,447	5,698,297	72,222,417
00070	Wayfinder Group Inc.	2,679	(4,272)	2,322	404	573	3,903	1,556	817	2,245	618	2,989	3,056	16,890
00071	Valley Appliance & Merchandise	1,011	578	1,027	208	530	314	527	293	574	499	638	314	6,514
00072	National Grid Billing Entity	265,202	177,158	307,796	486,571	227,414	55,086	692,195	134,230	(43,370)	121,660	3,674,988	117,161	6,216,091
00076	NGrid Communications Billing	-	(67,303)	-	-	-	-	-	-	-	-	-	-	(67,303)
00082	GridAmerica Holdings	-	(43)	450	-	1,637	92	-	-	-	-	-	-	2,137
00085	NEES Energy, Inc.	1,075	110	2,016	564	633	474	566	561	560	575	571	568	8,272
00086	EUA Energy Investment	223	286	214	224	223	211	226	225	224	226	229	228	2,740
00092	Prudence Corporation	-	-	53	-	-	-	-	-	-	-	-	-	53
00093	Patience Corporation	-	270	53	-	-	-	-	-	-	-	2,168	-	2,490
00094	Newport America Corporation	-	216	53	-	-	-	-	-	-	-	-	-	268
00095	Metrowest Realty LLC	261	2,186	198	268	432	1,051	664	1,206	631	759	711	687	9,054
00402	Essex Gas Company	32	64	(22)	942	2,442	2,624	2,702	1,427	2,298	2,571	2,472	3,886	21,439
00457	KeySpan Energy Services Inc.	-	-	-	-	-	-	-	-	2,893	-	-	-	2,893
00460	KeySpan Corporation	-	-	-	249	-	-	-	7,017	27,284	121,483	777	-	156,810
01401	Boston Gas Company Billing BU	105,785	521,398	1,213,636	(1,003,792)	696,609	170,129	312,069	210,149	496,039	344,168	444,505	482,414	3,993,110
01403	Colonial Lowell Div Billing BU	21,358	103,489	241,335	(200,703)	129,531	30,291	56,427	35,983	87,580	59,270	80,485	78,602	723,647
01404	Colonial Cape Cod Billing BU	-	-	505	920	2,657	3,428	2,874	2,995	27,155	9,317	2,619	11,016	63,487
01406	EnergyNorth Nat Gas Billing BU	11,865	56,918	132,372	(106,943)	84,957	21,987	36,322	28,964	63,492	47,530	58,379	52,581	488,424
01431	KeySpan Corp Serv Billing BU	5,000	(5,702)	-	6,813	28,720	-	206	1,079	-	6,912	-	2,667	45,695
01434	KeySpan Electric Srv BillingBU	116,077	597,673	1,489,117	(701,769)	964,818	133,397	404,299	167,055	987,414	598,817	553,544	428,928	5,739,371
01435	KeySpan Generation Billing BU	47,947	250,101	584,845	(514,717)	426,089	64,963	159,167	71,364	236,887	126,104	196,467	153,405	1,802,621
01436	KeySpan Energy Dev Billing BU	777	4,283	9,983	(9,064)	5,836	667	2,001	838	2,656	1,282	2,234	1,696	23,191
01437	KS Gas East Corp KEDLI Bill BU	70,201	348,389	824,450	(670,179)	505,343	108,945	225,837	125,993	318,204	207,454	284,951	278,327	2,627,915
01438	Brklyn Union Gas KEDNY Bill BU	157,499	795,584	1,857,867	(1,539,254)	990,154	209,379	427,710	243,103	618,157	391,884	546,495	532,562	5,231,141
01442	KS Ravenswood Srvcs Billing BU	36,295	197,191	458,679	(414,883)	212,587	32,798	79,895	36,256	119,668	63,799	98,766	77,317	998,370
01444	KS Energy Trading Billing BU	135	179	257	80	78	198	258	327	757	450	394	404	3,518
01446	KS Glenwood Energy Billing BU	1,327	7,720	18,231	(16,804)	12,004	1,653	4,260	1,714	6,001	3,150	5,193	3,963	48,412
01448	KS Port Jeff Energy Billing BU	1,263	7,336	17,325	(15,966)	9,175	1,264	3,256	1,310	4,590	2,410	3,970	3,030	38,962
01458	KS Energy Supply Billing BU	131	557	2,077	(1,049)	-	-	-	-	-	-	-	-	1,717
01459	KS Services Billing BU	6,945	103,300	319,679	19,279	43,747	56,293	87,602	44,179	587,863	42,060	18,678	24,403	1,354,028
01471	Seneca Upshur Billing BU	4,365	23,420	54,784	(49,486)	31,415	3,711	10,928	4,709	14,757	7,177	12,261	9,376	127,417
01563	KeySpan E&P JV Billing BU	711	4,169	9,856	(9,103)	3,167	312	1,028	370	1,245	579	1,117	820	14,270
	Total Charged from NGRID USA Service Co.	$48,728,478	$50,034,655	$67,275,352	$38,628,450	$53,781,325	$54,663,954	$50,958,660	$48,235,295	$68,419,366	$55,616,025	$55,368,032	$58,369,328	$650,078,922

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2008 Amounts Charged from KeySpan Service Companies to Affiliates by Month

	Charged Company	JANUARY-08	FEBRUARY-08	MARCH-08	APRIL-08	MAY-08	JUNE-08	JULY-08	AUGUST-08	SEPTEMBER-08	OCTOBER-08	NOVEMBER-08	DECEMBER-08	
01	BOSTON GAS COMPANY	4.814.286	6,029,161	12,435,123	5,030.907	7,059.055	7.065,851	5,250,303	5,533,563	7,037.447	8,967,243	7.331.440	7,128,422	83,682,801
02	ESSEX COUNTY GAS COMPANY	(2,114)	23,499	321.025	(14.210)	(2.356)	16,271	13,172	(9.352)	(1.112)	76,142	(12.481)	(29.850)	378,634
03	Colonial Lowell Division	1,004,111	1,350,353	3,007,210	1,028,314	1,545,934	1,485,660	1,079,136	1,308,460	1,502,877	1,598,619	1,263,274	1,598,591	17,772,540
04	Colonial Cape Cod Div	533	17,176	306,456	10,757	30,605	24,858	66,522	37,031	69,296	148,813	57,280	45,840	815,170
05	COLONIAL ADMINISTRATION	-	-	-	-	-	-	-	-	-	-	-	-	-
06	EnergyNorth Company	555,554	786,358	1,734,329	615.123	910,769	934,911	677,212	716,329	888,097	926,105	738.225	941,872	10,424,884
07	KEYSPAN NEW ENGLAND LLC	15,439	8,386	9,110	13,917	5,931	5,771	6,490	2,594	6,344	32,428	6.298	11,744	124,449
29	KEYSPAN MONEY POOLS	870,271	1,318,607	1,400,738	1,076.749	833,459	659,172	793,456	798,352	819,007	737,632	907.436	68,613	10,283,490
34	KEYSPAN ELECTRIC SERVICES, LLC	7.330,168	10,604,187	17,902,722	10,222.125	13,657,734	12.551,841	9,201,753	10,806,803	12,826,580	12,049,661	11,200,272	13,170,944	141,524,788
35	KEYSPAN GENERATION SERVICES,LLC	3.408,846	4,619,580	7,112,171	5,233.423	7,540,461	6,911,382	4,753,220	4,913,671	6,345,742	4,325,268	4,116.621	4,691,599	63,971,984
36	KEYSPAN ENERGY DEVELOPMENT	193,676	309,111	604.353	290.878	422.919	349,425	451.353	366,926	438.729	404,890	319.085	493.805	4,645,150
37	KEYSPAN ENERGY DELIVERY LI	5.614,690	6.931.661	12,782.183	6.585.840	8,459.561	9.107,660	5,703.291	7,571.817	7,786,730	8,304,320	7.463.842	8,539.198	94,850,792
38	KEYSPAN ENERGY DELIVERY NY	8,048,367	10,189,772	21,455,789	8,651,101	12,851,582	12,720,613	8,907,075	10,699,882	10,911,477	12,705,172	11,352,474	12,634,463	141,127,768
41	TRANSCANADA RAVENSWOOD	-	-	-	35,674	-	-	-	-	-	-	-	-	35,674
42	TRANSCANADA RAV SERVICES	1,673,063	2,608,102	4,984,780	2,092,730	3,364,432	2,950,748	2,109,382	2,303,527	1,373	61,435	88,834	-	22,238,406
44	KEYSPAN ENERGY TRADING SERVICES, LLC	196,758	305,589	1,407,520	470,245	627,294	363,639	256,754	401,214	742,176	528,744	417,076	424,066	6,141,076
46	KEYSPAN GLENWOOD ENERGY CENTER LLC	133,261	103,087	167,734	151.254	253,118	346,477	166,485	239,506	263,403	251,814	250.352	170,793	2,497,283
47	KEYSPAN SPAGNOLI ROAD ENERGY CENTER LLC	-	-	-	-	-	-	-	-	-	-	-	-	-
48	KEYSPAN PORT JEFFERSON ENERGY CENTER LLC	108,835	138,772	237,798	392.537	237,761	178,359	265,951	238,296	179,303	258,866	201.944	210,183	2,648,604
57	KEYSPAN ENERGY SERVICES INC.	17,026	33,324	82,720	36.466	51,817	35,550	23,532	39,380	15,572	13,423	13.605	22,035	384,450
58	KEYSPAN ENERGY SUPPLY INC.	97,470	240,338	(337,808)	-	-	-	-	-	-	-	-	-	-
59	KEYSPAN SERVICES INC	588.504	837.437	1,472.272	1,113.244	1.138,483	1.301,309	951,292	1.285.196	1.339,963	1.180,187	1.111.673	1.469,902	13,789,463
60	KEYSPAN ENERGY CORP	(1,598,356)	(1,823,420)	(1,858,392)	(1,827,667)	(1,788,485)	(1,735,306)	(1,876,333)	(1,302,045)	(1,542,953)	(1,812,375)	(1,828,767)	(1,664,483)	(20,658,581)
71	SENECA UPSHUR PETROLEUM	36,560	58,496	117,196	101,577	126,433	135,510	88,141	145,808	123,898	91,642	77,875	145,772	1,248,909
82	NG RAVENSWOOD SERV (post Sale)	-	-	-	-	-	-	-	-	2,949,558	2,343,852	2,093,315	2,656,072	10,042,797
C4	KEYSPAN LNG LP REGULATED ENTITY	(3,177)	-	-	-	-	-	-	-	-	-	-	-	(3,177)
D1	TRANSGAS	-	-	-	-	-	-	-	-	-	-	-	-	-
F1	KEYSPAN E&P JOINT VENTURE 50%	2,568	3,743	6,397	206	211	245	82	590	253	77	240	239	14,851
KT	KEYSPAN TECHNOLOGIES	-	-	-	-	-	-	-	-	-	-	-	-	-
NA	National Grid USA (Parent)	2,250	5,004	14,877	5,987	6,119	7.096	2,372	17,110	7,348	2,220	6,971	6,943	84,297
NB	Nantucket Electric Company	1,540	4,852	9,383	6,714	7,085	8,702	4,785	15,696	45,805	12.211	16,107	13,150	146,028
NC	Massachusetts Electric Company	90,155	277.084	488.330	407.868	431,743	557,525	341.873	961,829	859,472	648,366	845.141	1,221,476	7,130,862
ND	New England Power Company	9,562	24.463	93,186	60.808	70.667	148.299	35,644	211.575	106.082	90,018	103.589	122,007	1,075,902
NE	Niagara Mohawk Power-Elect Dist	208,000	599,916	1,300,344	993,063	1,125,097	1,029,045	640,040	1,693,865	1,192,745	1,161,152	1,536.308	1,339,485	12,819,059
NF	Granite State Electric Company	3,124	9,549	17,605	14,630	14,946	21,698	13,648	40,543	46,391	31,941	47,200	42,346	303,623
NG	Narragansett Gas Company	110,814	71,196	230,962	195,422	326,534	464,521	251,221	516,605	325,403	990,164	982,003	581,415	5,046,260
NH	Narragansett Electric Company	38,065	115,559	206,561	163,124	328,643	214,204	130,721	388,861	281,567	249,663	315.911	274,973	2,707,853
NK	NGUSA Service Company, Inc.	-	-	-	-	-	-	-	-	-	-	-	1,556	1,556
NL	NE Hydro-Trans Elec Co, Inc.	995	2,213	6,580	4,336	4,431	5.138	1,717	12,390	5,321	1,607	5,048	5,028	54,806
NN	NE Hydro-Trans Corporation	865	1,925	5,722	3,716	3,798	4.404	1,472	10,620	4,561	1,378	4,327	4,310	47,098
NO	NE Electric Trans Corporation	130	289	858	413	422	489	164	1,180	507	153	481	479	5,564
NP	Niagara Mohawk Power-Gas	-	-	-	-	-	381.293	163.983	532.935	464,806	606,508	352.199	427,331	2,929,055
NQ	Niagara Mohawk Power-Trans	-	-	-	-	-	75.122	25.729	180.050	83.543	24.088	80.282	85.559	554,372
Grand Total		33,571,839	45,805,369	87,725,833	43,167,274	59,646,202	58,327,483	40,501,636	50,680,805	56,127,312	57,013,427	51,465,479	56,855,880	640,888,539

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2009 Amounts Charged from NGRID USA Service Co. to Affiliates by Month

	Charged Company	January 2009	February 2009	March 2009	April 2009	May 2009	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	
00001	National Grid USA	$628,768	$241,989	$513,307	$207,774	$229,817	$252,320	$179,444	$189,304	$700,945	$134,153	$271,340	$312,153	$3,861,314
00004	Nantucket Electric Company	125,396	139,001	198,756	107,585	115,369	176,490	108,572	114,811	143,222	153,161	143,004	145,668	1,671,033
00005	Massachusetts Electric Company	20,447,054	32,308,740	27,887,508	14,100,708	15,880,038	19,171,850	13,549,995	14,612,026	16,625,128	16,202,387	15,498,854	15,562,854	221,847,141
00006	NE Hydro - Trans Electric Co	244,585	265,146	302,690	267,307	281,950	273,483	265,867	235,122	256,258	301,200	365,497	305,467	3,364,572
00007	New England Hydro Finance Co	-	-	-	-	-	1	(1)	-	355	(512)	126	-	(31)
00008	New England Hydro - Trans Corp	49,738	66,260	67,950	77,887	73,952	119,619	59,647	83,261	88,098	121,419	68,927	78,917	955,674
00010	New England Power Company	4,139,054	4,691,585	7,642,434	4,236,401	3,402,927	5,168,720	3,875,435	4,081,275	5,753,280	5,232,259	4,441,698	4,952,961	57,618,030
00020	New England Electric Trans Co	32,336	26,421	39,754	14,982	16,598	23,820	38,480	150,614	197,045	90,521	159,966	(1,458,467)	(667,931)
00021	National Grid Trans Services	(1,194)	3,084	2,767	6,386	3,214	3,257	3,038	3,473	3,226	3,086	3,228	3,332	36,895
00035	Niagara Mohawk Holdings, Inc.	-	-	-	120	-	4	(4)	-	-	-	19,029	24,258	43,407
00036	Niagara Mohawk Power Corp	23,395,846	37,952,716	40,177,479	17,223,600	19,325,394	29,856,499	20,139,325	19,844,079	28,804,889	22,788,684	22,347,968	24,358,920	306,215,399
00037	Opinac North America, Inc	-	-	-	-	-	8	(8)	-	-	-	-	-	-
00041	Granite State Electric Company	844,229	743,547	817,358	482,040	531,072	562,414	448,764	464,295	552,447	540,873	535,245	563,316	7,085,600
00048	Narragansett Gas Company	1,639,163	2,297,159	3,648,655	1,773,484	1,950,962	2,455,994	2,090,562	2,306,159	2,253,002	3,077,384	2,128,516	2,627,677	28,248,718
00049	Narragansett Electric Company	5,466,219	8,213,961	9,274,444	4,665,068	5,242,781	7,101,348	4,779,748	5,087,121	5,875,427	5,955,877	5,371,482	5,890,472	72,923,948
00070	Wayfinder Group Inc.	27,163	1,594	5,581	10,119	2,368	2,922	1,774	2,523	2,435	(751)	1,676	1,558	58,962
00071	Valley Appliance & Merchandise	(2,151)	1,012	445	1,590	300	(36)	100	101	99	(273)	12	9	1,207
00072	National Grid Billing Entity	63,097	219,983	1,945,740	507,533	131,245	398,733	211,438	137,672	507,810	582,625	131,878	154,131	4,991,884
00082	GridAmerica Holdings	597	100	61,844	895	200	246	200	267	200	(131)	100	100	64,617
00083	GridAmerica LLC	-	-	-	-	-	-	140	-	-	-	(140)	-	-
00085	NEES Energy, Inc.	1,118	671	957	1,754	748	753	1,033	3,455	766	732	746	744	13,477
00086	EUA Energy Investment	871	330	325	1,218	425	424	427	436	435	453	424	424	6,191
00092	Prudence Corporation	139	-	-	12	16	17	12	14	14	14	14	14	268
00093	Patience Corporation	139	-	-	-	-	1	140	67	-	-	-	-	347
00094	Newport America Corporation	595	-	-	-	-	2	-	299	-	-	-	-	896
00095	Metrowest Realty LLC	2,256	921	837	1,154	504	523	626	505	2,020	3,700	2,693	4,568	20,306
00402	Essex Gas Company	9,577	1,404	6,227	4,727	8,033	4,364	3,789	4,225	5,879	5,308	5,153	31,394	90,082
00460	KeySpan Corporation	-	-	-	-	-	-	1,806	-	-	-	-	-	1,806
01401	Boston Gas Company Billing BU	415,440	1,984,513	1,642,153	799,263	803,673	1,687,365	766,218	1,405,091	1,782,474	1,249,532	1,389,297	1,548,237	15,473,256
01403	Colonial Lowell Div Billing BU	79,685	350,522	304,785	131,318	158,073	298,858	134,541	200,472	280,931	188,361	227,176	266,261	2,620,983
01404	Colonial Cape Cod Billing BU	13,255	13,371	18,863	11,433	5,076	17,209	4,996	6,204	4,378	5,500	6,671	6,515	113,471
01406	EnergyNorth Nat Gas Billing BU	54,356	289,911	218,363	81,245	91,586	227,582	85,379	114,515	150,751	105,239	121,653	127,167	1,667,747
01431	KeySpan Corp Serv Billing BU	13,811	17,182	(234,312)	77,202	29,486	18,755	10,286	20,599	9,097	8,994	11,255	54,871	37,226
01434	KeySpan Electric Srv BillingBU	421,335	1,984,972	1,854,614	898,341	601,317	1,712,751	758,408	1,212,187	1,674,150	846,575	1,247,008	1,193,505	14,405,163
01435	KeySpan Generation Billing BU	192,157	566,091	965,397	245,759	248,350	694,675	299,449	348,254	527,341	383,737	313,999	405,744	5,190,952
01436	KeySpan Energy Dev Billing BU	1,809	(11,623)	11,506	2,901	2,797	9,447	3,438	3,920	5,901	4,113	3,326	9,110	46,644
01437	KS Gas East Corp KEDLI Bill BU	274,002	1,637,775	1,158,520	535,593	427,319	1,212,813	325,621	719,514	1,061,550	649,716	749,466	890,836	9,642,723
01438	Brklyn Union Gas KEDNY Bill BU	519,121	3,223,690	3,816,238	1,230,770	850,424	2,303,157	861,234	1,428,307	2,288,160	1,360,693	1,404,301	1,623,636	20,909,732
01442	KS Ravenswood Srvcs Billing BU	96,970	271,458	337,805	-	-	-	133	-	-	-	-	-	706,366
01444	KS Energy Trading Billing BU	566	(4,885)	1,539	926	672	728	908	758	1,904	489	989	944	5,539
01446	KS Glenwood Energy Billing BU	4,911	12,407	25,367	4,277	4,239	13,735	5,300	7,626	9,368	7,259	5,582	7,513	107,582
01448	KS Port Jeff Energy Billing BU	3,755	7,722	19,441	4,438	4,399	14,254	5,467	8,033	9,675	7,519	5,781	7,781	98,266
01458	KS Energy Supply Billing BU	-	22	-	-	-	-	4	-	-	-	-	-	25
01459	KS Services Billing BU	25,140	(150,675)	37,253	25,635	26,683	30,552	28,248	32,370	166,107	14,177	42,528	20,691	298,710
01471	Seneca Upshur Billing BU	10,080	11,857	62,812	13,062	14,523	44,611	18,092	19,827	32,276	19,951	17,869	20,982	285,942
01563	KeySpan E&P JV Billing BU	836	4,381	5,876	976	1,283	4,681	1,561	1,840	2,266	1,934	1,408	1,782	28,823
	Total Charged from NGRID USA Service Co.	$59,241,823	$97,384,315	$102,841,278	$47,755,480	$50,467,813	$73,864,946	$49,069,633	$52,850,617	$69,779,309	$60,045,961	$57,045,742	$59,746,048	$780,092,965

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2009 Amounts Charged from KeySpan Service Companies to Affiliates by Month

	Charged Company	JANUARY-09	FEBRUARY-09	MARCH-09	APRIL-09	MAY-09	JUNE-09	JULY-09	AUGUST-09	SEPTEMBER-09	OCTOBER-09	NOVEMBER-09	DECEMBER-09	
01	BOSTON GAS COMPANY	5,111,285	6,314,505	10,045,868	4,928,831	6,470,664	6,501,350	4,300,557	7,614,947	6,346,650	4,817,151	4,726,248	7,452,008	74,630,065
02	ESSEX COUNTY GAS COMPANY	(111,493)	(13,670)	(25,294)	(8,271)	21,223	27,630	16,711	15,357	15,539	274,164	222,334	415,951	850,180
03	Colonial Lowell Division	1,033,371	1,211,466	2,118,865	1,117,397	1,320,430	1,519,552	943,187	1,660,945	1,559,007	1,122,562	1,172,662	1,586,017	16,365,461
04	Colonial Cape Cod Div	(218,724)	32,354	(12,712)	(5,687)	13,700	53,613	68,863	88,987	25,131	106,841	100,666	137,989	391,023
06	EnergyNorth Company	437,989	623,035	1,047,747	574,477	738,138	838,130	582,423	1,027,339	817,066	561,423	749,947	1,224,158	9,221,871
07	KEYSPAN NEW ENGLAND LLC	16,888	54,216	35,582	16,258	8,717	14,295	18,590	17,397	5,918	7,343	29,300	43,566	268,070
29	KEYSPAN MONEY POOLS	326,452	303,562	73,426	225,092	154,574	148,455	269,377	225,446	205,623	187,875	400,695	486,215	3,006,793
34	KEYSPAN ELECTRIC SERVICES, LLC	9,855,607	11,197,202	17,248,877	10,686,152	11,664,737	12,928,208	9,271,343	11,378,326	12,077,040	10,884,050	9,936,602	12,599,659	139,727,803
35	KEYSPAN GENERATION SERVICES,LLC	3,117,482	4,921,953	8,199,087	6,873,111	7,288,680	7,854,199	5,749,156	5,510,574	6,150,638	5,897,851	5,171,492	5,495,493	72,229,717
36	KEYSPAN ENERGY DEVELOPMENT	262,941	541,550	1,151,612	304,594	328,711	381,241	233,301	402,949	535,529	245,683	229,910	365,535	4,983,555
37	KEYSPAN ENERGY DELIVERY LI	6,115,062	6,828,167	11,395,777	6,068,354	7,016,153	7,829,099	5,645,598	7,325,360	7,672,943	6,754,655	6,193,918	7,457,688	86,302,775
38	KEYSPAN ENERGY DELIVERY NY	9,573,700	10,718,018	17,580,960	9,369,285	10,457,712	11,595,465	9,274,604	11,234,549	13,263,230	9,789,515	9,114,921	10,642,039	132,613,998
41	TRANSCANADA RAVENSWOOD	-	-	-	-	-	-	-	-	-	-	-	-	-
42	TRANSCANADA RAV SERVICES	-	-	-	-	-	-	-	-	-	-	-	-	-
44	KEYSPAN ENERGY TRADING SERVICES, LLC	265,544	334,080	488,594	403,178	377,644	392,746	220,943	425,569	276,702	225,324	197,395	285,669	3,893,387
45	LIPA	-	-	-	-	-	-	-	-	-	-	-	-	-
46	KEYSPAN GLENWOOD ENERGY CENTER LLC	113,472	137,269	231,985	310,654	275,092	169,881	240,787	165,506	194,675	251,537	159,663	190,993	2,441,514
47	KEYSPAN SPAGNOLI ROAD ENERGY CENTER LLC	-	-	-	-	-	-	-	-	-	-	-	-	-
48	KEYSPAN PORT JEFFERSON ENERGY CENTER LLC	118,084	145,940	284,411	319,857	221,677	270,942	296,065	189,705	278,046	168,065	156,167	206,697	2,655,657
57	KEYSPAN ENERGY SERVICES INC.	-	-	(334)	-	-	-	-	-	-	-	-	-	(334)
58	KEYSPAN ENERGY SUPPLY INC.	-	-	-	-	-	-	-	-	-	-	-	-	-
59	KEYSPAN SERVICES INC	936,529	1,091,341	2,049,746	792,036	838,656	859,177	606,879	847,750	956,825	789,715	796,976	1,189,513	11,755,144
60	KEYSPAN ENERGY CORP	(1,501,502)	(1,866,830)	71,665	(2,485,854)	(1,783,228)	(1,833,060)	(1,603,141)	(1,719,169)	(1,831,452)	(1,825,614)	(1,892,765)	(1,800,836)	(20,071,787)
71	SENECA UPSHUR PETROLEUM	70,475	81,083	197,665	31,889	39,491	37,958	25,268	40,372	41,959	29,581	32,849	63,955	692,546
82	NG RAVENSWOOD SERV (post Sale)	1,584,246	2,030,069	3,442,668	10,312	3,867	(14,313)	(8,123)	(13,690)	(1,084,102)	-	-	-	5,950,934
C4	KEYSPAN LNG LP REGULATED ENTITY	-	-	-	-	-	-	-	-	-	-	-	-	-
D1	TRANSGAS	-	-	6,685	-	-	-	-	-	-	-	-	-	6,685
F1	KEYSPAN E&P JOINT VENTURE 50%	239	132	791	588	966	986	731	950	1,493	819	938	1,827	10,460
KT	KEYSPAN TECHNOLOGIES	-	-	-	-	-	-	-	-	-	-	-	-	-
NA	National Grid USA (Parent)	6,931	3,825	22,945	7,643	12,640	13,081	9,614	12,656	19,578	10,973	12,491	24,040	156,416
NB	Nantucket Electric Company	9,344	10,514	86,797	19,685	23,547	30,935	17,862	28,449	36,990	25,317	25,728	38,369	353,535
NC	Massachusetts Electric Company	707,565	670,976	1,934,697	1,012,154	1,397,495	1,687,607	993,635	1,536,544	2,057,761	1,326,521	1,382,971	2,168,377	16,876,303
ND	New England Power Company	140,659	125,111	273,595	134,427	251,307	216,842	148,921	188,770	261,773	173,865	184,627	313,983	2,413,879
NE	Niagara Mohawk Power-Elect Dist	913,963	897,825	3,072,151	1,516,220	2,266,189	2,662,253	1,644,130	2,507,639	3,404,590	2,063,962	2,221,544	3,493,943	26,664,409
NF	Granite State Electric Company	38,645	65,147	147,181	49,819	63,645	77,763	38,190	66,051	86,123	54,964	56,341	90,572	834,441
NG	Narragansett Gas Company	(325,623)	145,902	969,881	451,253	780,843	854,218	631,046	1,145,526	1,134,785	737,924	801,481	1,148,519	8,475,756
NH	Narragansett Electric Company	209,622	216,193	614,391	408,802	576,145	716,171	440,622	640,639	996,068	572,927	597,486	932,535	6,921,601
NK	NGUSA Service Company, Inc.	(1,556)	1,556	(1,556)	1,556	-	-	-	-	-	-	-	-	-
NL	NE Hydro-Trans Elec Co, Inc.	5,019	2,770	16,615	5,879	9,848	10,450	7,942	10,201	15,488	8,845	9,831	18,941	121,830
NN	NE Hydro-Trans Corporation	4,302	2,374	14,242	4,409	7,394	7,865	5,983	7,682	11,642	6,663	7,394	14,235	94,185
NO	NE Electric Trans Corporation	478	264	1,582	294	495	531	406	520	783	452	499	957	7,260
NP	Niagara Mohawk Power-Gas	479,095	516,908	1,464,136	537,503	845,607	1,486,219	860,681	2,132,597	1,795,773	1,105,410	1,397,277	1,634,322	14,255,528
NQ	Niagara Mohawk Power-Trans	83,260	63,568	260,400	128,823	210,122	211,935	149,356	204,682	310,876	172,914	188,602	349,978	2,334,514
Grand Total		39,379,351	47,408,378	84,510,728	43,810,719	51,902,879	57,551,425	41,101,505	54,921,126	57,640,692	46,549,277	44,386,192	58,272,904	627,435,176

Date of Request: February 17, 2010
Due Date: March 1, 2010

Request No. RAV-13 SUPP
NMPC Req. No. NM 18 DPS 18

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid
Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO:

Request:
A. For each month, January 2006 through December 2009, please provide a breakdown of total service company costs charged to every individual affiliate of National Grid, both regulated and unregulated; also include 2006 – 2009 annual amounts. Please provide this information broken down between those costs allocated from the National Grid – USA service company, the KeySpan service company, and in total.
B. Same as A, for the rate years' forecasted amounts.
C. Please provide monthly updates for A. above until further notice.
Note: Please provide the information in an excel spreadsheet, not a pdf file.

SUPPLEMENT: Please provide the NMPC amounts split apart between E &G.

Response:
SUPP: As requested, please see RAV-13 SUPP Attachment 1, which supplements the information provided in the response to RAV-13.

Name of Respondent:
Andrew Sloey

Date of Reply:
March 1, 2010

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Annual Amounts Charged from KeySpan Service Companies to Niagara Mohawk by Segment

Company	Company Description	SEP - DEC 2007	2008	2009	TOTAL
NE	Niagara Mohawk Power-Elect Dist	735,154.38	12,819,059.35	26,664,409.15	**40,218,622.88**
NP	Niagara Mohawk Power-Gas	0.00	2,929,055.24	14,255,528.49	**17,184,583.73**
NQ	Niagara Mohawk Power-Trans	0.00	554,372.32	2,334,514.11	**2,888,886.43**
Grand Total		**735,154.38**	**16,302,486.91**	**43,254,451.75**	**60,292,093.04**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2009 Amounts Charged from KeySpan Service Companies to NMPC by Segment

Company	Company Description	JANUARY-09	FEBRUARY-09	MARCH-09	APRIL-09	MAY-09	JUNE-09	JULY-09	AUGUST-09	SEPTEMBER-09	OCTOBER-09	NOVEMBER-09	DECEMBER-09	TOTAL
NE	Niagara Mohawk Power-Elect Dist	913,962.87	897,825.16	3,072,150.65	1,516,220.03	2,266,188.83	2,662,253.46	1,644,130.10	2,507,639.29	3,404,589.83	2,063,962.03	2,221,544.38	3,493,942.52	26,664,409.15
NP	Niagara Mohawk Power-Gas	479,095.24	516,907.66	1,464,135.86	537,503.42	845,607.15	1,486,219.31	860,680.77	2,132,596.90	1,795,773.28	1,105,409.87	1,397,276.99	1,634,322.04	14,255,528.49
NQ	Niagara Mohawk Power-Trans	83,259.57	63,568.27	260,400.16	128,822.96	210,121.55	211,934.89	149,355.56	204,681.50	310,875.63	172,914.39	188,602.01	349,977.62	2,334,514.11
Grand Total		1,476,317.68	1,478,301.09	4,796,686.67	2,182,546.41	3,321,917.53	4,360,407.66	2,654,166.43	4,844,917.69	5,511,238.74	3,342,286.29	3,807,423.38	5,478,242.18	43,254,451.75

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2008 Amounts Charged from KeySpan Service Companies to NMPC by Segment

Company	Company Description	JANUARY-08	FEBRUARY-08	MARCH-08	APRIL-08	MAY-08	JUNE-08	JULY-08	AUGUST-08	SEPTEMBER-08	OCTOBER-08	NOVEMBER-08	DECEMBER-08	TOTAL
NE	Niagara Mohawk Power-Elect Dist	208,000.43	599,915.91	1,300,344.15	993,062.55	1,125,096.96	1,029,045.43	640,039.60	1,693,864.92	1,192,745.23	1,161,151.89	1,536,307.53	1,339,484.75	12,819,059.35
NP	Niagara Mohawk Power-Gas	0.00	0.00	0.00	0.00	0.00	381,293.04	163,983.39	532,935.18	464,805.83	606,508.13	352,198.66	427,331.01	2,929,055.24
NQ	Niagara Mohawk Power-Trans	0.00	0.00	0.00	0.00	0.00	75,122.10	25,728.50	180,050.07	83,543.23	24,087.64	80,281.96	85,558.82	554,372.32
Grand Total		**208,000.43**	**599,915.91**	**1,300,344.15**	**993,062.55**	**1,125,096.96**	**1,485,460.57**	**829,751.49**	**2,406,850.17**	**1,741,094.29**	**1,791,747.66**	**1,968,788.15**	**1,852,374.58**	**16,302,486.91**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
For the Post Merger period August 27 (September 1) - December 31,Calendar Year 2007 Amounts Charged from KeySpan Service Companies to NMPC by Segment

Company	Company Description	SEPTEMBER-07	OCTOBER-07	NOVEMBER-07	DECEMBER-07	TOTAL
NE	Niagara Mohawk Power-Elect Dist	0.00	0.00	340,605.43	394,548.95	**735,154.38**
NP	Niagara Mohawk Power-Gas	0.00	0.00	0.00	0.00	**0.00**
NQ	Niagara Mohawk Power-Trans	0.00	0.00	0.00	0.00	**0.00**
Grand Total		**0.00**	**0.00**	**340,605.43**	**394,548.95**	**735,154.38**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Annual Amounts Charged from NGRID USA Service Co. to Niagara Mohawk by Segment

Company	Company Description	2006	2007	2008	2009	TOTAL
NE	Niagara Mohawk Power-Elect Dist	138,176,844.88	160,723,647.11	179,762,174.05	217,476,846.21	**696,139,512.25**
NP	Niagara Mohawk Power-Gas	25,372,367.13	30,098,236.79	30,547,968.38	37,515,937.84	**123,534,510.13**
NQ	Niagara Mohawk Power-Trans	29,159,048.01	38,658,258.91	45,194,761.10	51,222,614.76	**164,234,682.78**
Grand Total		**192,708,260.02**	**229,480,142.81**	**255,504,903.52**	**306,215,398.81**	**983,908,705.16**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2009 Amounts Charged from NGRID USA Service Co. to NMPC by Segment

Company	Company Description	JANUARY-09	FEBRUARY-09	MARCH-09	APRIL-09	MAY-09	JUNE-09	JULY-09	AUGUST-09	SEPTEMBER-09	OCTOBER-09	NOVEMBER-09	DECEMBER-09	TOTAL
NE	Niagara Mohawk Power-Elect Dist	16,970,772.71	30,505,675.91	29,846,723.66	12,307,052.88	14,073,600.34	21,293,207.47	13,429,169.00	14,223,122.48	19,583,665.61	14,828,321.83	15,389,242.80	15,026,291.52	217,476,846.21
NP	Niagara Mohawk Power-Gas	2,757,316.28	3,691,549.73	4,084,608.38	1,836,444.35	2,635,266.43	4,372,448.27	2,599,818.88	2,623,407.41	3,598,910.71	3,139,419.21	2,532,472.66	3,644,275.53	37,515,937.84
NQ	Niagara Mohawk Power-Trans	3,667,756.60	3,755,490.82	6,246,146.49	3,080,102.34	2,616,527.53	4,190,842.88	4,110,337.32	2,997,548.98	5,622,313.04	4,820,943.29	4,426,252.53	5,688,352.94	51,222,614.76
Grand Total		23,395,845.59	37,952,716.46	40,177,478.53	17,223,599.57	19,325,394.30	29,856,498.62	20,139,325.20	19,844,078.87	28,804,889.36	22,788,684.33	22,347,967.99	24,358,919.99	306,215,398.81

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2008 Amounts Charged from NGRID USA Service Co. to NMPC by Segment

Company	Company Description	JANUARY-08	FEBRUARY-08	MARCH-08	APRIL-08	MAY-08	JUNE-08	JULY-08	AUGUST-08	SEPTEMBER-08	OCTOBER-08	NOVEMBER-08	DECEMBER-08	TOTAL
NE	Niagara Mohawk Power-Elect Dist	13,357,325.56	14,783,790.81	14,290,502.14	12,539,713.60	13,807,879.64	17,688,049.80	13,315,427.91	15,094,424.35	19,366,733.53	15,522,769.49	13,855,015.42	16,140,541.80	**179,762,174.05**
NP	Niagara Mohawk Power-Gas	2,290,598.14	1,982,261.83	2,318,426.12	1,975,685.99	2,272,766.27	2,906,001.16	2,673,389.57	2,400,211.88	3,636,566.81	2,664,462.94	2,485,786.57	2,941,811.10	**30,547,968.38**
NQ	Niagara Mohawk Power-Trans	3,442,919.39	3,050,451.04	5,835,491.97	2,438,862.11	3,105,057.57	3,176,987.70	4,127,251.36	3,004,105.19	4,574,947.59	3,980,198.49	5,047,892.88	3,410,595.81	**45,194,761.10**
Grand Total		**19,090,843.09**	**19,816,503.68**	**22,444,420.22**	**16,954,261.70**	**19,185,703.48**	**23,771,038.66**	**20,116,068.84**	**20,498,741.42**	**27,578,247.93**	**22,167,430.92**	**21,388,694.87**	**22,492,948.71**	**255,504,903.52**

RAV-13 SUPP Attachment 1

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2007 Amounts Charged from NGRID USA Service Co. to NMPC by Segment

Company	Company Description	JANUARY-07	FEBRUARY-07	MARCH-07	APRIL-07	MAY-07	JUNE-07	JULY-07	AUGUST-07	SEPTEMBER-07	OCTOBER-07	NOVEMBER-07	DECEMBER-07	TOTAL
NE	Niagara Mohawk Power-Elect Dist	14,392,226.69	13,235,806.40	14,525,497.15	10,102,734.58	13,823,378.01	11,610,078.30	13,828,424.56	14,941,218.21	13,778,337.79	14,918,850.88	13,152,478.13	12,414,616.42	**160,723,647.11**
NP	Niagara Mohawk Power-Gas	2,153,485.46	2,364,731.96	2,914,472.29	1,882,462.96	2,622,924.88	2,342,750.33	2,636,340.65	2,882,571.74	2,741,183.75	2,869,804.40	2,156,199.97	2,531,308.40	**30,098,236.79**
NQ	Niagara Mohawk Power-Trans	2,673,234.26	2,779,789.71	4,538,984.89	1,761,089.59	2,242,911.50	2,526,663.54	3,341,899.33	3,598,372.45	2,850,586.78	3,342,093.03	3,693,434.22	5,309,199.61	**38,658,258.91**
Grand Total		**19,218,946.41**	**18,380,328.07**	**21,978,954.33**	**13,746,287.13**	**18,689,214.39**	**16,479,492.17**	**19,806,664.54**	**21,422,162.40**	**19,370,108.32**	**21,130,748.31**	**19,002,112.32**	**20,255,124.43**	**229,480,142.81**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Calendar Year 2006 Amounts Charged from NGRID USA Service Co. to NMPC by Segment

Company	Company Description	JANUARY-06	FEBRUARY-06	MARCH-06	APRIL-06	MAY-06	JUNE-06	JULY-06	AUGUST-06	SEPTEMBER-06	OCTOBER-06	NOVEMBER-06	DECEMBER-06	TOTAL
NE	Niagara Mohawk Power-Elect Dist	11,965,898.43	10,117,407.39	9,507,118.04	9,406,758.03	10,245,253.93	11,135,273.20	11,561,302.57	11,049,101.99	11,211,191.10	14,038,395.55	15,035,949.23	12,903,195.43	**138,176,844.88**
NP	Niagara Mohawk Power-Gas	2,010,317.50	1,634,618.43	1,526,119.51	1,689,762.22	1,936,221.41	2,139,844.72	2,319,124.07	2,031,525.61	2,297,362.09	2,718,270.40	2,550,660.16	2,518,541.01	**25,372,367.13**
NQ	Niagara Mohawk Power-Trans	2,635,727.94	2,204,064.57	2,701,861.09	1,703,921.34	2,190,699.04	2,137,852.50	2,150,798.71	1,915,719.00	2,558,216.53	3,346,576.36	2,706,879.12	2,906,731.81	**29,159,048.01**
Grand Total		**16,611,943.87**	**13,956,090.39**	**13,735,098.63**	**12,800,441.59**	**14,372,174.38**	**15,412,970.42**	**16,031,225.35**	**14,996,346.60**	**16,066,769.71**	**20,103,242.31**	**20,293,488.51**	**18,328,468.25**	**192,708,260.02**

Date of Request: February 10, 2010
Due Date: February 22, 2010

Request No. CVB-1
NMPC Req. No. NM 19 DPS-19

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christian Bonvin

TO: Infrastructure and Operations Panel

Request:

1. Please provide an excel file containing the following information for each distribution and sub-transmission blanket project on a total company basis (i.e. does not need to reflect line items for East, Central, West):
A. Approved budgets from FY05/06 through FY09/10
B. Actual expenditures for FY05/06 through FY08/09
C. Forecasted expenditure for FY09/10 (using actual expenditures incurred to date)
D. Forecasted expenditures for FY10/11 through FY14/15
2. Please explain instances, if any, where a blanket account has been modified over the fiscal years to reflect a different work level (≤ $100,000), subsume or remove other blanket accounts, or otherwise changed such that year to year comparison would be inappropriate.

Response:

1. Figures are provided in Attachment 1 (CVB-1_Attach 1_Blanket Capital Project Analysis.xls).
   A. See Columns labeled **C, E, G, I,** and **K** for the appropriate categories.
   B. See Columns labeled **D, F, H,** and **J** for the appropriate categories.
   C. See Column labeled **L** for the appropriate categories.
   D. See Columns labeled **M, N, O, P,** and **Q** for the appropriate categories.

Form 103

2. Over the time period included in the Information Request CVB-1, blanket projects have evolved differently for Distribution vs. Sub-Transmission. Therefore this portion of the response will address them separately.

DISTRIBUTION BLANKET PROJECTS:

Instances where a blanket project has been modified over the fiscal years such that year to year comparison would be inappropriate:

a. All blankets in FY2005/06 and FY2006/07 included more work orders over $100k than in more recent years. FY07/08 and beyond have separated these larger work orders into specific project numbers to improve monitoring, resource planning and overall project approval. These larger work orders occurred more frequently in New Business, Public Requirements, Load Relief and Asset Replacement categories.
b. General Equipment – In FY08/09 a significant accounting adjustment relating to prior and current year was made to reinstate the previous Niagara Mohawk general equipment capitalization limit of $200 (Column J – Row 4).
c. Public Requirements – FY07/08 actuals (Column H – Row 9) included an accounting adjustment of over $7M for benefits overhead adjustment.

SUB-TRANSMISSION BLANKET PROJECTS

Divisional Sub-Transmission blanket projects (project numbers CNE071 to CNW077) were set up in June 2007. They were first used in fiscal year 2007/08 for a portion of the year and budgeted for the first time in fiscal year 2008/09. The intent of these projects is to better controls for the budgeting, approval, and tracking of work in these various categories. Prior to establishing these projects, certain specific projects were utilized to collect costs within current blanket-type categories but without the $100k work order limit. In the enclosed budget-to-actual excel spreadsheet, we have mapped these types of projects to represent the budgets and actuals for the sub-transmission blanket classifications. This "map" is provided in Attachment 2, (CVB-1_Attach 2_TxD Blanket Map.xls)

Name of Respondent:	Date of Reply:
Glen DiConza	February 18, 2010

BLANKET CAPITAL PROJECT ANALYSIS
NIAGARA MOHAWK ($000)
DISTRIBUTION

ROW #	A	B	C	D	E	F	G	H	I	J	K	L
1	Blanket # / Blanket Description		[redacted]	FY05/06 Actual Spend	[redacted]	FY06/07 Actual Spend	[redacted]	FY07/08 Actual Spend	[redacted]	FY08/09 Actual Spend	[redacted]	
2	002	Substation Blanket	-	882	-	767	750	955	780	1,190	1,099	1,979
3	004	Meter Blanket (installs & purchases)	2,024	2,389	2,700	4,943	5,600	6,691	6,058	5,661	7,006	3,350
4	006/070	Genl Equip Blanket	1,475	2,155	1,300	810	1,000	1,460	614	8,275	647	3,177
5	009	Land/Rights Blanket	-	1,478	1,210	1,776	1,750	1,154	1,820	1,718	1,945	1,919
6	010	New Bus-Resid Blankt	31,202	41,227	34,200	41,439	45,500	35,055	35,756	29,649	25,492	27,724
7	011	New Bus-Comm Blanket	3,205	10,973	8,500	9,426	10,900	11,466	10,968	11,516	9,245	12,166
8	012	Outdoor Lighting	6,873	7,082	6,700	7,029	7,900	7,361	6,596	8,113	7,258	6,400
9	013	Public Requir Blankt	6,841	9,590	7,000	8,290	9,690	15,417	8,756	3,212	7,340	4,282
10	014	Damage&Failure Blnkt	5,091	8,161	6,300	11,232	10,700	13,044	13,098	14,175	18,241	15,213
11	015	Reliability Blanket	1,783	6,737	4,500	5,079	6,200	4,220	4,869	7,270	7,432	8,428
12	016	Load Relief Blanket	2,363	6,715	4,500	1,355	2,000	1,001	1,360	1,334	2,695	1,375
13	017	Asset Replace Blankt	6,237	6,915	5,700	7,555	8,000	4,885	3,838	6,642	6,961	9,370
14	020	Transf/Capac Blanket	21,942	25,182	20,000	24,488	23,400	25,428	22,738	23,174	23,920	24,276
15	021	Dist - Telecom	428	510	550	64	150	(151)	156	1	24	(4)
16	022	3rd Party Attch Blnkt	156	457	500	292	450	128	468	156	252	294
17	TOTAL		[redacted]	130,453	[redacted]	124,545	[redacted]	128,114	[redacted]	122,086	[redacted]	

18
19 BLANKET CAPITAL PROJECT ANALYSIS
20 NIAGARA MOHAWK ($000)
21 SUB-TRANSMISSION
22

ROW #	A	B	C	D	E	F	G	H	I	J	K	L
23	Blanket # / Blanket Description		[redacted]	FY05/06 Actual Spend	[redacted]	FY06/07 Actual Spend	[redacted]	FY07/08 Actual Spend	[redacted]	FY08/09 Actual Spend	[redacted]	
24	071	New Business (All)	-	502	-	88	100	458	750	20	241	430
25	072	Public Requirements	492	556	450	920	(230)	(592)	750	85	145	55
26	073	Damage/Failure	1,023	1,533	1,725	1,332	1,950	1,709	1,600	2,812	1,304	2,750
27	074	Substation Blanket	-	54	25	180	555	427	750	829	757	972
28	075	Asset Replacement	180	694	450	576	450	1,995	2,909	1,321	716	1,400
29	076	Reliability	-	-	-	-	-	72	750	439	615	575
30	077	Load Relief	-	35	-	127	-	298	750	272	99	50
31	TOTAL		[redacted]	3,374	[redacted]	3,223	[redacted]	4,367	[redacted]	5,778	[redacted]	

ROW #	M	N	O	P	Q
1	[redacted]				
2	1,362	1,440	1,493	1,545	1,605
3	7,132	7,765	8,329	8,844	9,492
4	1,987	4,070	4,211	4,359	4,511
5	1,920	2,076	2,245	2,428	2,626
6	27,773	29,802	31,428	32,917	34,642
7	12,520	13,190	13,830	14,415	15,054
8	8,172	8,629	8,982	9,323	9,733
9	4,346	4,619	4,861	5,082	5,333
10	14,453	15,284	15,850	16,405	17,045
11	6,631	7,181	7,754	8,284	8,900
12	1,104	1,144	1,193	1,233	1,288
13	5,750	5,750	5,150	4,600	4,000
14	26,830	29,933	32,536	34,539	37,242
15	30	30	30	30	30
16	265	280	290	300	310
17	[redacted]				
18					
19					
20					
21					
22					
23	[redacted]				
24	531	553	574	595	615
25	264	293	309	316	331
26	3,087	3,181	3,268	3,354	3,442
27	532	586	617	631	661
28	930	966	995	1,031	1,050
29	514	528	542	556	569
30	105	110	114	118	122
31	[redacted]				

Niagara Mohawk Power Corp.
TxD Blanket Map

BUSINESS UNIT	PROJECT	BLANKET # ASSIGNED	BLANKET TYPE	PROJECT DESCRIPTION	LONG DESC
00036	C00399	072	Public Requirements	DOT/Mandated Central Region Sub-Tra	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00415	072	Public Requirements	DOT/Mandated Mohawk Valley Region S	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00421	072	Public Requirements	DOT/Mandated Northern Region Sub-Tr	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00434	072	Public Requirements	DOT/Mandated Capital Region Sub-Tra	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00465	072	Public Requirements	DOT/Mandated Northeast (23-69kV) Re	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00474	073	Damage/Failure	12kV and 23kV Cable Failure Repairs	Repair 12kV (Niagara Falls) and 23kV (Buffalo) subtransmission cable failures as they occur to maintain system integrity.
00036	C00486	072	Public Requirements	DOT/Mandated Frontier Region Sub-Tr	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00501	072	Public Requirements	DOT/Mandated Western Region Sub-Tra	Relocation of subtransmission facilities due to mandate by governmental authorities such as NYSDOT, Counties and Municipalities.
00036	C00512	074	Substation Blanket (Damage	Capital Region SubTransmission (23-	Replacement of failed SubTransmission Station Equipment (23-69kV) in the Capital Region
00036	C00517	074	Substation Blanket (Damage	Frontier Region SubTransmission (12	Replacement of failed SubTransmission Station Equipment (12-69kV) in the Frontier Region
00036	C00518	074	Substation Blanket (Damage	Western Region SubTransmission (23-	Replacement of failed SubTransmission Station Equipment (23-69kV) in the Western Region
00036	C03820	077	Load Relief	West Div Misc SubT Conv Projects	West Div Misc SubT Conv Projects
00036	C03823	077	Load Relief	Central Div Misc SubT Conv Projects	Central Div Misc SubT Conv Projects
00036	C03824	073	Damage/Failure	Central Div SubT Cable Failures	Central Div SubT Cable Failures
00036	C03827	077	Load Relief	East Div Misc SubT Conv Projects	East Div Misc SubT Conv Projects

BUSINESS UNIT	PROJECT	BLANKET # ASSIGNED	BLANKET TYPE	PROJECT DESCRIPTION	LONG DESC
00036	C03828	073	Damage/Failure	East Div SubT Cable Failures	East Div SubT Cable Failures
00036	C03921	074	Substation Blanket (Damage	Rpl Failed Sub-T Sta Equip-Cent Div	Replace failed SubT Station Equipment (12-69kV) in the Central Division
00036	C03940	077	Load Relief	East Div SubT Stations Conv	East Div SubT Stations Conv
00036	C03941	077	Load Relief	Cent Div SubT Stations Conv	Cent Div SubT Stations Conv
00036	C03942	077	Load Relief	West Div SubT Stations Conv	West Div SubT Stations Conv
00036	C04243	071	New Business	23 kV New Service Projects	
00036	C04246	075	Asset Replacement	12-23 kV Cable Retirements	
00036	C04313	074	Substation Blanket (Damage	West NY-SubT-Subs Blanket	Replacement of failed Sub Transmission Station Equipment (23kV-69 kV) in Westrn Region
00036	C04314	074	Substation Blanket (Damage	Central NY-SubT-Subs Blanket	
00036	C04315	074	Substation Blanket (Damage	East NY-SubT-Subs Blanket	
00036	C04685	075	Asset Replacement	Sub-Transmission B-Maint Capital	Sub-Transmission 23-69 kV B-Maintenance
00036	C04688	075	Asset Replacement	Subtransmission B Maintenance	B mainteneance that is able to be capitalized.
00036	C05884	071	New Business	Sub-T Customer Work	Customer related work on the 34.5 kV system
00036	C06004	075	Asset Replacement	Sub-Transmission A-Maint Capital	Sub-T A Maintenance Work - Capital $
00036	C06837	074	Substation Blanket (Damage	Replacement of failed Sub-Transmission Sta	Replacement of failed Sub-Transmission Station Equipment (12-69 kV) in all Divisions
00036	C06874	072	Public Requirements	Cent Div Sub-T DOT Relocates FY07	Relocations associated with highway rearrangements that affect Sub-T facilities in the Central Division for FY07.
00036	C07100	073	Damage/Failure	Cent Div Sub-T Emergency Work	Covers the capitalizable Sub-T line work identified as emergency.
00036	C07104	075	Asset Replacement	Cent Div Sub-T Capitalizable PM Wrk	Covers all identified Sub-T PM work that is capitalizable for the Central Division
00036	C04689	075	Asset Replacement	Central Div Sub-T PM Capital Work	This covers the costs associated with capitalizable PM work for the Sub-T facilities in the Central Division
00036	C07237	071	New Business	Customer Requirements/Taps	Customer Requirements/Taps
00036	C07238	075	Asset Replacement	Capitalizeable B-Maintenance	Capitalizeable B-Maintenance
00036	C07541	075	Asset Replacement	Cent Div Sub-T Line Retirements	Covers to any costs associated with Sub-Transmission line retirements for the Central Division
00036	C07548	074	Substation Blanket (Damage	Replacement of failed SubTransmission Sta	Replacement of failed SubTransmission Station Equipment (23-69kV) in the Capital Region
00036	C07549	074	Substation Blanket (Damage	Replacement of failed SubTransmission Sta	Replacement of failed SubTransmission Station Equipment (23-69kV) in the Northeast Region
00036	C18555	074	Substation Blanket (Damage	TxD Substation Dmg/Fail Reserve C36	Company 36 Substation Damage/Failure Reserve for Transmission Managed By Distribution
00036	C21631	075	Asset Replacement	NY SubT Asset Replacement	This funding is for asset replacement of subt poles or equipment
00036	CNC071	071	New Business	CNY Sub Trans-Line New Business	Central NY Sub Trans-Line New Business

BUSINESS UNIT	PROJECT	BLANKET # ASSIGNED	BLANKET TYPE	PROJECT DESCRIPTION	LONG DESC
00036	CNC072	072	Public Requirements	CNY Sub Trans-Line Public Require	Central NY Sub Trans-Line Public Require
00036	CNC073	073	Damage/Failure	CNY Sub Trans-Line Damage Failure	Central NY Sub Trans-Line Damage Failure
00036	CNC074	074	Substation Blanket (Damage	CNY Sub Trans-Substation Blanket	Central NY Sub Trans-Substation Blanket
00036	CNC075	075	Asset Replacement	CNY Sub Trans-Line Asset Replace	Central NY Sub Trans-Line Asset Replace
00036	CNC076	076	Reliability	CNY Sub Trans-Line Reliability	Central NY Sub Trans-Line Reliability
00036	CNC077	076	Reliability	CNY Sub Trans-Line Load Relief	Central NY Sub Trans-Line Load Relief
00036	CNE071	071	New Business	ENY Sub Trans-Line New Business	East NY Sub Trans-Line New Business
00036	CNE072	072	Public Requirements	ENY Sub Trans-Line Public Require	East NY Sub Trans-Line Public Require
00036	CNE073	073	Damage/Failure	ENY Sub Trans-Line Damage Failure	East NY Sub Trans-Line Damage Failure
00036	CNE074	074	Substation Blanket (Damage	ENY Sub Trans-Substation Blanket	East NY Sub Trans-Substation Blanket
00036	CNE075	075	Asset Replacement	ENY Sub Trans-Line Asset Replace	East NY Sub Trans-Line Asset Replace
00036	CNE076	076	Reliability	ENY Sub Trans-Line Reliability	East NY Sub Trans-Line Reliability
00036	CNE077	072	Public Requirements	ENY Sub Trans-Line Load Relief	East NY Sub Trans-Line Load Relief
00036	CNW071	071	New Business	WNY Sub Trans-Line New Business	West NY Sub Trans-Line New Business
00036	CNW072	072	Public Requirements	WNY Sub Trans-Line Public Require	West NY Sub Trans-Line Public Require
00036	CNW073	073	Damage/Failure	WNY Sub Trans-Line Damage Failure	West NY Sub Trans-Line Damage Failure
00036	CNW074	074	Substation Blanket (Damage	WNY Sub Trans-Substation Blanket	West NY Sub Trans-Substation Blanket
00036	CNW075	075	Asset Replacement	WNY Sub Trans-Line Asset Replace	West NY Sub Trans-Line Asset Replace
00036	CNW076	076	Reliability	WNY Sub Trans-Line Reliability	West NY Sub Trans-Line Reliability
00036	CNW077	077	Load Relief	WNY Sub Trans-Line Load Relief	West NY Sub Trans-Line Load Relief

Date of Request: February 11, 2010 Request No. DPS-22(DSM-1)
Due Date: February 22, 2010

NMPC Req. No. ___

NIAGARA MOHAWK POWER CORPORATION

Case No.10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid

Electric Rates

Request for Information

FROM: David Morrell

TO: Infrastructure and Operations Panel

Request:

A. Please provide a complete breakdown (cost and volume, e.g. acres ROW edge miles, etc.) for all transmission vegetation management activities planned for the rate years. Items may include routine ROW floor treatment acres, widening edge miles, trimming, danger trees, mowing and other.

B. Please provide what voltage classes are covered in item #1 answer.

Response:

A. See Attachment 1 (DSM-1_Attach 1_ Transmission Veg Management Rate Year Estimates).

The Integrated Vegetation Management acres presented in Attachment 1 are an average of actual acres treated between the years 2006 through 2009, as shown below.

New York Integrated Vegetation Management Acres (2006 – 2009)		
YEAR	**ACRES**	
2006	9,041	As reported to the PSC in the 2006 transmission right of way management program report
2007	7,633	As reported to the PSC in the 2007 transmission right of way management program report
2008	7,368	As reported to the PSC in the 2008 transmission right of way management program report
2009	10,066	Acres treated in 2009 Pending Final Verification
4 year average acres	8,527	

B. The voltage classes covered in Attachment 1 are 23kV through 345kV for transmission lines, and 12kV through 345kV for substations. Please note that there can be numerous operating voltages on a single right-of-way.

Name of Respondent: Date of Reply:

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Niagara Mohawk Power Corp

Transmission Veg Management Rate Year Estimates

Vegetation Management Activities	Voltage (kV)	CY2011 (based on 4 year avg. acres)	CY2011 (projected cost)	CY2012 (based on 4 year avg. acres)	CY2012 (projected cost)	CY2013 (based on 4 year avg. acres)	CY2013 (projected cost)
TRIM-STC-MOW	23 - 46	333	$477,611.00	333	$491,939.00	333	$506,697.00
(trim, prune/cut, stump treat & chip/mechanical brush mowing)	69 - 345	295	$423,108.00	295	$435,802.00	295	$448,876.00
TOTALS		628	$900,719.00 **	628	$927,741.00	628	$955,573.00
	Voltage (kV)	CY2011 (based on 4 year avg. acres)	CY2011 (projected cost)	CY2012 (based on 4 year avg. acres)	CY2012 (projected cost)	CY2013 (based on 4 year avg. acres)	CY2013 (projected cost)
INTEGRATED VEGETATION MANAGEMENT	23 - 46	2,132	$680,108.00	2,132	$701,428.00	2,132	$720,616.00
	69 - 345	6,395	$2,040,005.00	6,395	$2,103,955.00	6,395	$2,161,510.00
TOTALS		8,527	$2,720,113.00	8,527	$2,805,383.00	8,527	$2,882,126.00
	Voltage (kV)	CY2011 (estimated miles)	CY2011 (projected cost)	CY2012 (estimated miles)	CY2012 (projected cost)	CY2013 (estimated miles)	CY2013 (projected cost)
DANGER TREE	23 - 46	108	$1,085,750.00	111	$1,118,322.50	115	$1,151,872.39
	69 - 345	126	$1,439,250.00	130	$1,482,427.50	134	$1,526,900.61
TOTALS		234	$2,525,000.00	241	$2,600,750.00	249	$2,678,773.00
	Voltage (kV)	CY2011	CY2011 (projected cost)	CY2012	CY2012 (projected cost)	CY2013	CY2013 (projected cost)
OFF-CYCLE	23 - 345	unplanned hazard tree removals	$440,840.00	unplanned hazard tree removals	$454,065.00	unplanned hazard tree removals	$467,687.00
	Voltage (kV)	CY2011 (projected miles)	CY2011 (projected cost)	CY2012 (projected miles)	CY2012 (projected cost)	CY2013 (projected miles)	CY2013 (projected cost)
SUB-T WIDENING	23 - 69	140	$3,488,239.00	140	$3,592,886.00	140	$3,700,673.00
	Voltage (kV)	CY2011 (acres)	CY2011 (projected cost)	CY2012 (acres)	CY2012 (projected cost)	CY2013 (acres)	CY2013 (projected cost)
SUBSTATIONS	12 - 345	877	$342,400.00	877	$352,672.00	877	$363,252.00
	Voltage (kV)	CY2011 (acres)	CY2011 (projected cost)	CY2012 (acres)	CY2012 (projected cost)	CY2013 (acres)	CY2013 (projected cost)
GRASS MOWING	23 - 345	1302	$130,000.00	1302	$133,900.00	1302	$137,917.00
	Voltage (kV)	CY2011 (projected miles)	CY2011 (cost)	CY2012 (projected miles)	CY2012 (cost)	CY2013 (projected miles)	CY2013 (cost)
115 KV WIDENING	115	50 - 110	$1,500,000.00	50 - 110	$1,500,000.00	50 - 110	$1,500,000.00

Date of Request: February 11, 2010 Request No. DPS-23(DSM-2)
Due Date: February 22, 2010

NMPC Req. No. ___

NIAGARA MOHAWK POWER CORPORATION

Case No.10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: David Morrell
TO: Infrastructure and Operations Panel
Request: Page 223 of Book 26 discusses a revenue requirement of $935,000 for the Company's ROW floor trim program. Relative to this program, please provide the following:

A. Supply the inventories that support the work requiring this expenditure.
B. How the work will be administered, i.e. lump sum bid or T&M?
C. The reason(s) these sites need to be treated outside the normal cycles.
D. The type of work that will be done on these sites, e.g. mow, hand cut, trim etc.

Response:

A. National Grid performs detailed site-by-site inventories for each transmission line right-of-way prior to scheduled maintenance. These inventories are performed after the previous growing season ends and prior to the treatment of the right-of-way. For this reason, no inventories are available for planned work in 2011, 2012 and 2013. The acres provided in Attachment 1 (DSM-1_Attach 1_Transmission Veg Management Rate Year Estimates) in DPS-22(DSM-1) for floor trim sites are an average of actual acres treated from the years 2006 through 2009, as shown below.

New York Floor Trim Site Acres (2006 - 2009)		
YEAR	**ACRES**	
2006	607	As reported to the PSC in the 2006 transmission right of way management program report
2007	702	As reported to the PSC in the 2007 transmission right of way management program report
2008	528	As reported to the PSC in the 2008 transmission right of way management program report
2009	677	Acres treated in 2009 pending final verification
4 year average acres	**628**	

B. The work will be administered on a Time & Material basis. However, beginning in 2010, the Company will initiate a pilot lump sum program for some floor trim sites and

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also several lines scheduled for danger tree work. The Company will assess the results of the lump sum pilot program and determine whether to expand the use of lump sum work in the future.

C. These floor trim sites will not be treated outside normal cycles. The indicated annual amounts are the funds necessary to maintain the average number of acres treated per year in on-cycle work.

D. The majority of work performed in the floor trim program will be tree pruning and tree removal.

Name of Respondent:	Date of Reply:
Dawn Travalini	February 22, 2010

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Date of Request: February 11, 2010 Request No. DPS-24(DSM-3)
Due Date: February 22, 2010

NMPC Req. No. ___

NIAGARA MOHAWK POWER CORPORATION

Case No.10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid

Electric Rates

Request for Information

FROM: David Morrell
TO: Infrastructure and Operations Panel
Request: Page 222 of Book #26 states the Company projects an annual cost of $1.5 million for 115 kV widening. Relative to this expenditure please provide the following:

A. Total ROW edge miles to be completed in this work scope.
B. Verification that property rights exist to complete this activity.
C. Number of 115 kV outages over the last five years from off-ROW trees (non storm).
D. Number of years for which this work is planned.
E. How this work will be administered, i.e. lump sum or time and material?
F. Lines 7 & 8 on page 222 state that all trees will be removed to a new cleared width. State what that new width will be in terms of feet from centerline.
G. Will this new cleared width area be included as part of on-going routine vegetation management acres or be allowed to grow back?
H. By stating "all trees" (line 7 page 222) does the Company mean all trees tall enough to strike to conductor or does it mean any tree species regardless of height at the time of work?
I. Provide inventory data (e.g. number of trees or ROW edge miles) supporting the need for this work product.

Response:

A. Between 50 and 110 miles of right-of-way (ROW) will be widened per year

B. Only ROW segments and individual properties within segments where we currently have adequate property rights will be widened under this program. Property rights are currently documented within our GIS system (Corridor Manager) by the Real Estate Assets Management Department, which is referenced prior to commencing work.

C. There were eighty-five (85) 115 kV sustained outages during the years 2005 through 2009. Please see Attachment 1 (DSM-3_Attach 1_New York 115 kV Sustained Vegetation-Caused Outages). This document presents sustained vegetation-caused outages on 115 kV lines for the years 2005 through 2009. Both storm and non-storm outages are presented in the document since all outages with impacts to customers are evaluated in selecting the ROWs to be widened. Of the 85 sustained outages, 54 outages occurred during PSC defined major storms.

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D. This work will be on-going and may run as long as 10 years depending on the number of candidate lines that will realize improved reliability from the program.

E. The work will be administered on a time and material basis utilizing rates that are competitively bid. Cost control is achieved through oversight by Transmission Foresters who visit the sites on a regular basis to monitor productivity and verify the work has been completed per specification.

F. Where rights allow, 115 kV ROW's will be widened to the edge of the existing ROW up to a maximum of 50 feet from centerline.

G. Where rights allow, the new width will be maintained to remove tall growing species on cycle within the ROW floor maintenance program (Integrated Vegetation Management). Where rights do not allow, it will be necessary to maintain this new width on cycle in the danger tree program, removing the trees when they attain sufficient height to be danger trees.

H. "All trees" refers to any tree listed as an "Undesirable Tall Growing Species" in the National Grid Transmission Right-of-Way Management Program (Part 84 Plan), or any "Medium Tree", as listed, that because of its proximity could enter the wire security zone (minimum clearance distance) of the transmission conductor.

I. There are 2,550 miles of 115 kV ROW in New York. In 2004, it was found that the New York 115 kV transmission system was exposed to approximately 628,000 danger trees. Our research reveals that the utility forest will increase to approximately 1.9 million trees between the years 2004 and 2019. Since most of tree-caused service interruptions are caused by trees outside the ROW, this area is targeted for reduction of danger trees. Because the utility forest is increasing in area, the current danger tree program, which targets identifiable hazard trees, will not keep pace with the increase in the number of danger trees. Our data since 1996 indicates that 68% of trees that fail and cause an outage event could not have been identified as hazard trees. Therefore, it is necessary to focus on danger trees to effect an improvement in reliability.

Name of Respondent:	Date of Reply:
Dawn Travalini	February 22, 2010

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Niagara Mohawk Power Corp
New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

Interruption & Disturbance System Event	Incident Report No.	Circuit Identification	Circuit Name	Outage Date/Time	Restore Date/Time	Storm?	Loss of Supply - Customers Interrupted	Lost Customer Minutes	Weather	Calendar Year	Sub-Region	Division
202355		T1100	Dunkirk - Falconer #162	1/8/05 15:35	1/8/05 15:36	N				2005	WSW	Western
208985		T1280	Gardenville - Homer Hill #152	4/2/05 19:49	4/2/05 19:50	Y				2005	WF	Western
209166		T1080	Dunkirk - Falconer #160	4/3/05 0:00	4/4/05 12:50	Y	11,524	57,620		2005	WSW	Western
209125		T1950	Gardenville - Homer Hill #151	4/3/05 9:42	4/3/05 23:30	Y	1	77		2005	WF	Western
215508		T5810	Ticonderoga - Republic #2	6/9/05 18:42	6/10/05 10:01	N	4,452	4,091,388		2005	ENE	Eastern
217871		T1550	Lockport - Mortimer #114	7/8/05 15:33	7/8/05 15:34	N				2005	WG	Western
219982		T1280	Gardenville - Homer Hill #152	7/26/05 17:38	7/27/05 17:47	Y	3,100	83,700		2005	WF	Western
219980		T1080	Dunkirk - Falconer #160	7/26/05 18:21	7/28/05 15:00	Y	11,527	314,029		2005	WSW	Western
225694		T1340	Homer Hill - Bennett Road #157	9/29/05 8:56	9/30/05 14:03	N	6,836	79,248		2005	WSW	Western
225717		T3280	McIntyre - Colton #8	9/29/05 12:22	9/30/05 18:27	N				2005	CN	Central
228107		T5270	Inghams - Stoner #9	10/19/05 19:39	10/20/05 19:26	N	10,328	888,208		2005	ENE	Eastern
231048		T1100	Dunkirk - Falconer #162	11/9/05 17:10	11/10/05 15:27	N	1,374	8,244		2005	WSW	Western
232948		T3210	Lake Colby - Lake Placid #3	11/29/05 8:34	11/29/05 15:26	Y	1,615	218,300		2005	CN	Central
232951		T3170	Colton - Malone #3	11/29/05 11:38	11/29/05 19:57	Y	555	33,855		2005	CN	Central
239946		T1170	Falconer - Homer Hill #154	2/17/06 7:26	2/18/06 14:28	Y	1	6	Rain - Heavy; Wind - Severe (55-73 mph); 49F	2006	WSW	Western
239781		T5690	Rotterdam - New Scotland #19	2/17/06 10:20	2/18/06 18:41	Y			Wind - Severe (55-73 mph)	2006	EC	Eastern
240240		T5810	Ticonderoga - Republic #2	2/17/06 11:25	2/17/06 21:54	Y	4,268	2,658,964		2006	ENE	Eastern
239840		T5750	Spier - Rotterdam #1	2/17/06 12:02	2/18/06 7:31	Y	18,900	21,320,000	Rain - Heavy; Wind - Severe (55-73 mph);	2006	ENE	Eastern
239842		T5760	Spier - Rotterdam #2	2/17/06 12:06	2/18/06 7:07	Y	19,855	22,655,000		2006	ENE	Eastern
239829		T5390	Meco - Rotterdam #10	2/17/06 15:08	2/19/06 9:22	Y			Wind - Severe (55-73 mph); 30F	2006	EC	Eastern
245301		T5880	Warrensburg - Scofield Road #10	5/24/06 15:34	5/25/06 21:03	N	3,496	279,680	Fair; Calm to light wind (0-12 mph); 65F	2006	ENE	Eastern
255890		T3140	Colton - Browns Falls #1	9/24/06 10:44	9/24/06 18:18	N	2,611	28,721	Rain - Heavy; Wind - Mild (13 - 31 mph); 65F	2006	CN	Central
256679		T1660	Niagara - Gardenville #180	10/13/06 4:50	10/13/06 18:00	Y	2,713	8,139	Freezing rain or sleet; Calm to light wind (0 - 12 mph); 32F	2006	WF	Western
		T1500	Lockport - Batavia #108	10/13/06 5:01	10/15/06 12:15	Y	3,900	7,800		2006	WG	Western
		T1550	Lockport - Mortimer #114	10/13/06 6:02	10/16/06 1:48	Y	1	642		2006	WG	Western
256689		T6020	Walck Road - Huntley #133	10/13/06 9:35	10/14/06 18:25	Y			Snow - Wet; Wind - Mild (13 - 31 mph); 33F	2006	WF	Western
		T1660	Niagara - Gardenville #180	10/13/06 19:51	10/14/06 1:50	Y				2006	WF	Western
256800		T3210	Lake Colby - Lake Placid #3	10/20/06 19:59	10/21/06 1:26	N	1,713	164,679	Freezing rain or sleet; Calm to light wind (0 - 12 mph); 33F	2006	CN	Central
256942		T1820	Packard - Huntley #130	10/28/06 23:17	10/29/06 18:20	Y	5,064	15,192	Rain - Light to moderate; Wind - Mild (13 - 31 mph); 36F	2006	WF	Western
257407		T1160	Falconer - Homer Hill #153	12/1/06 14:55	12/4/06 20:46	Y	1	860	Rain - Light to Moderate;Major Storm; 48F	2006	WSW	Western
257408		T1170	Falconer - Homer Hill #154	12/1/06 14:55	12/6/06 15:25	Y	1	860	Rain - Light to Moderate;Major Storm; 48F	2006	WSW	Western

New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

Interruption & Disturbance System Event	Incident Report No.	Circuit Identification	Circuit Name	Outage Date/Time	Restore Date/Time	Storm?	Loss of Supply - Customers Interrupted	Lost Customer Minutes	Weather	Calendar Year	Sub-Region	Division
257443		T6060	Mohican - North Troy #3	12/2/06 6:52	12/2/06 17:28	Y	2,576	110,768	Fair; wind - Mild (13 - 31 mph); 40F	2006	ENE	Eastern
257885		T5440	Mohican - Butler #18	1/15/07 9:08	1/16/07 21:49	Y	5,377	205,339	Freezing Rain or Sleet; Calm to light wind (0 - 12 mph); 28F	2007	ENE	Eastern
258829		T5820	Ticonderoga - Hague Road #4	4/15/07 19:21	4/18/07 12:59	N			Snow - West; Major Storm	2007	ENE	Eastern
259283		T1610	Mortimer (Sta.82) - Quaker (Sta.121) #23	5/15/07 21:44	5/16/07 7:30	N			Rain - light / moderate, Thunderstorms, 60F	2007	WG	Western
259589		T1610	Mortimer (Sta.82) - Quaker (Sta.121) #23	6/3/07 1:12	6/3/07 10:03	N			Fair; Mild	2007	WG	Western
259808		T1090	Dunkirk - Falconer #161	6/13/07 13:52	6/14/07 12:34	N	2,848	50,707	Fair	2007	WSW	Western
259869		T4220	Porter - Schuyler #13	6/19/07 16:27	6/20/07 2:15	N			Rain - heavy	2007	CMV	Central
259877		T1160	Falconer - Homer Hill #153	6/19/07 18:19	6/21/07 8:25	N	1	40	Rain - heavy	2007	WSW	Western
260041		T5350	Maplewood - Menands #19	6/27/07 17:39	6/28/07 23:19	N			Extreme hot or cold, temp 90	2007	EC	Eastern
260358		T5880	Warrensburg - Scofield Road #10	7/10/07 19:10	7/11/07 4:30	Y	1,618	967,564	Major Storm	2007	ENE	Eastern
260358		T5770	Spier - West #9	7/10/07 19:10	7/12/07 1:31	Y			Major storm	2007	ENE	Eastern
261354		T1580	Mortimer - Golah #110	9/11/07 22:07	9/12/07 8:12	N			Rain-heavy	2007	WG	Western
262616		T3340	Taylorville - Moshier #7	12/29/07 8:03	12/29/07 8:08	N	258	1,290	Wind -Strong	2007	CN	Central
262720		T3340	Taylorville - Moshier #7	1/9/08 9:59	1/9/08 23:59	N	256	222,464	Rain Wind Severe	2008	CN	Central
262800		T1550	Lockport - Mortimer #114	1/13/08 13:25	1/13/08 13:26	N			Fair	2008	WG	Western
262801		T1550	Lockport - Mortimer #114	1/13/08 13:43	1/14/08 17:37	N	1	3	Fair	2008	WG	Western
262990		T1280	Gardenville - Homer Hill #152	1/30/08 4:34	1/30/08 23:41	Y	4,116	185,220	Severe Winds, Rain/Sleet/Ice	2008	WF	Western
263001		T1900	Valley (Sta. 44) - Ischua Switch #158	1/30/08 6:17	1/30/08 10:07	Y	3,046	700,580	Severe Winds, Rain/Sleet/Ice	2008	WSW	Western
263163		T1300	Gardenville - Seneca #82	2/6/08 16:53	2/13/08 8:40	N	2,080	199,680	Freezing Rain/Wind	2008	WF	Western
263187		T1390	Huntley - Gardenville #39	2/6/08 20:08	2/7/08 17:02	Y			Freezing Rain/Wind	2008	WF	Western
263504		T2140	Curtis Street - Teall #13	3/8/08 21:23	3/8/08 21:29	N	12,020	72,120	Snow-wet	2008	CC	Central
266706		T1170	Falconer - Homer Hill #154	6/6/08 8:30	6/6/08 16:16	N	2	534	Fair	2008	WSW	Western
267156		T2120	Coffeen - Black River - Lighthouse Hill #5	6/10/08 11:40	6/11/08 18:32	Y	5,611	28,055	TStorms	2008	CN	Central
267179		T3140	Colton - Browns Falls #1	6/10/08 12:26	6/11/08 18:42	Y	2,649	4,807,935	TStorms	2008	CN	Central
267182		T3150	Colton - Browns Falls #2	6/10/08 12:50	6/11/08 20:16	Y			TStorms	2008	CN	Central
267503		T3160	Colton - Townline #9	6/10/08 12:53	6/10/08 23:39	Y	5	3,230	TStorms	2008	CN	Central
267184		T3170	Colton - Malone #3	6/10/08 13:02	6/11/08 19:25	Y	2,762	196,102	TStorms	2008	CN	Central
267216		T6060	Mohican - North Troy #3	6/10/08 20:21	6/11/08 18:18	Y	2,458	125,358	TStorms	2008	ENE	Eastern
276966		T1820	Packard - Huntley #130	9/14/08 21:19	9/15/08 2:33	Y	5,065	50,650	Rain,High Winds	2008	WF	Western
277026		T1900	Valley (Sta. 44) - Ischua Switch #158	9/14/08 22:58	9/15/08 8:16	Y	1,372	760,088	Rain,High Winds	2008	WSW	Western
276990		T2560	Sleight Road - Auburn (State St.) #3	9/15/08 1:53	9/15/08 19:01	Y	1	963	Rain,High Winds	2008	WG	Western
276989		T2120	Coffeen - Black River - Lighthouse Hill #5	9/15/08 3:06	9/15/08 23:43	Y	6,618	19,854	Rain,High Winds	2008	CN	Central
276991		T3340	Taylorville - Moshier #7	9/15/08 3:33	9/15/08 21:43	Y	256	277,248	Rain,High Winds	2008	CN	Central
277347		T6070	Spier - Mohican #7	9/18/08 10:09	9/18/08 15:45	N			Fair	2008	ENE	Eastern
282780		T5940	Feura Bush - North Catskill #2	12/12/08 2:13	12/12/08 21:29	Y			Ice/Snow	2008	EC	Eastern
282781		T5760	Spier - Rotterdam #2	12/12/08 2:38	12/13/08 0:10	Y	14,957	29,914	Ice/Snow	2008	ENE	Eastern
282785		T5690	Rotterdam - New Scotland #19	12/12/08 3:34	12/13/08 12:41	Y			Ice/Snow	2008	EC	Eastern
282786		T5080	Lafarge Bldg Matls - Pleasant Valley #8	12/12/08 3:46	12/13/08 19:55	Y	750	779,250	Ice/Snow	2008	EC	Eastern
284867		T1390	Huntley - Gardenville #39	12/28/08 8:22	12/28/08 17:37	Y	37	111	Fair, Severe Wind	2008	WF	Western
284872		T1340	Homer Hill - Bennett Road #157	12/28/08 9:50	12/30/08 13:38	Y	424	72,928	Fair, Severe Wind	2008	WSW	Western
284878		T1450	Huntley - Lockport #37	12/28/08 10:23	12/30/08 22:08	Y			Fair, Severe Wind	2008	WF	Western

New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

Interruption & Disturbance System Event	Incident Report No.	Circuit Identification	Circuit Name	Outage Date/Time	Restore Date/Time	Storm?	Loss of Supply - Customers Interrupted	Lost Customer Minutes	Weather	Calendar Year	Sub-Region	Division
287677		T1280	Gardenville - Homer Hill #152	2/12/09 11:16	2/13/09 18:49	Y	4,166	41,660	Wet Snow, Strong Winds	2009	WF	Western
296317	21124-0	T1530	Lockport - Mortimer #111	6/9/09 10:37	6/9/09 17:29	N	6,721	20,163	Fair, Mild Wind	2009	WG	Western
301688	21154-0	T2560	Sleight Road - Auburn (State St.) #3	7/26/09 15:03	7/26/09 17:15	N			Heavy Rain, Thunderstorms	2009	WG	Western
303052	21163-1	T1080	Dunkirk - Falconer #160	8/9/09 23:27	8/10/09 11:45	Y	10,959	397,173	Rain-heavy/Thunderstorms	2009	WSW	Western
303139	21164-0	T1270	Gardenville - Dunkirk #142	8/10/09 12:06	8/10/09 18:43	Y			Fair/Mild wind	2009	WF	Western
303598	21173-1	T1950	Gardenville - Homer Hill #151	8/22/09 3:26	8/22/09 13:47	N	2	126	Fair/Calm to light wind	2009	WF	Western
304212	21182-0	T2560	Sleight Road - Auburn (State St.) #3	10/7/09 15:49	10/8/09 1:29	N	1	60	Rain-light/Strong wind	2009	WG	Western
304452	21183-0	T1170	Falconer - Homer Hill #154	10/29/09 10:28	10/30/09 15:27	N	1	32	Fair/Calm to light wind	2009	WSW	Western
304907	21197-1	T1260	Gardenville - Dunkirk #141	12/9/09 6:29	12/9/09 6:30	Y			Dry Snow, Strong Wind	2009	WF	Western
304908	21197-1	T1280	Gardenville - Homer Hill #152	12/9/09 6:44	12/9/09 11:11	Y	4,187	25,122	Dry Snow, Strong Wind	2009	WF	Western
304909	21197-1	T1600	Mortimer - Pannell Road #25	12/9/09 8:11	12/9/09 14:12	Y			Dry Snow, Strong Wind	2009	WG	Western
304906	21197-1	T1260	Gardenville - Dunkirk #141	12/9/09 8:13	12/9/09 8:14	Y			Dry Snow, Strong Wind	2009	WF	Western
304913	21197-1	T1260	Gardenville - Dunkirk #141	12/9/09 9:44	12/9/09 18:22	Y	26,968	678,187	Dry Snow, Strong Wind	2009	WF	Western

Date of Request: February 11, 2010 Request No. DPS-24(DSM-3) [SUPP]
Due Date: February 22, 2010

NMPC Req. No. ___

NIAGARA MOHAWK POWER CORPORATION

Case No.10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid

Electric Rates

Request for Information

FROM: David Morrell

TO: Infrastructure and Operations Panel

Request: Page 222 of Book #26 states the Company projects an annual cost of $1.5 million for 115 kV widening. Relative to this expenditure please provide the following:

A. Total ROW edge miles to be completed in this work scope.
B. Verification that property rights exist to complete this activity.
C. Number of 115 kV outages over the last five years from off-ROW trees (non storm).
D. Number of years for which this work is planned.
E. How this work will be administered, i.e. lump sum or time and material?
F. Lines 7 & 8 on page 222 state that all trees will be removed to a new cleared width. State what that new width will be in terms of feet from centerline.
G. Will this new cleared width area be included as part of on-going routine vegetation management acres or be allowed to grow back?
H. By stating "all trees" (line 7 page 222) does the Company mean all trees tall enough to strike to conductor or does it mean any tree species regardless of height at the time of work?
I. Provide inventory data (e.g. number of trees or ROW edge miles) supporting the need for this work product.

Response:

A. Between 50 and 110 miles of right-of-way (ROW) will be widened per year

B. Only ROW segments and individual properties within segments where we currently have adequate property rights will be widened under this program. Property rights are currently documented within our GIS system (Corridor Manager) by the Real Estate Assets Management Department, which is referenced prior to commencing work.

C. There were eighty-five (85) 115 kV sustained outages during the years 2005 through 2009. Please see Attachment 1 (DSM-3_Attach 1_New York 115 kV Sustained Vegetation-Caused Outages). This document presents sustained vegetation-caused outages on 115 kV lines for the years 2005 through 2009. Both storm and non-storm outages are presented in the document since all outages with impacts to customers are evaluated in selecting the ROWs to be widened. Of the 85 sustained outages, 54 outages occurred during PSC defined major storms.

D. This work will be on-going and may run as long as 10 years depending on the number of candidate lines that will realize improved reliability from the program.

E. The work will be administered on a time and material basis utilizing rates that are competitively bid. Cost control is achieved through oversight by Transmission Foresters who visit the sites on a regular basis to monitor productivity and verify the work has been completed per specification.

F. Where rights allow, 115 kV ROW's will be widened to a maximum of 50 feet from the outside conductor.

G. Where rights allow, the new width will be maintained to remove tall growing species on cycle within the ROW floor maintenance program (Integrated Vegetation Management). Where rights do not allow, it will be necessary to maintain this new width on cycle in the danger tree program, removing the trees when they attain sufficient height to be danger trees.

H. "All trees" refers to any tree listed as an "Undesirable Tall Growing Species" in the National Grid Transmission Right-of-Way Management Program (Part 84 Plan), or any "Medium Tree", as listed, that because of its proximity could enter the wire security zone (minimum clearance distance) of the transmission conductor.

I. There are 2,550 miles of 115 kV ROW in New York. In 2004, it was found that the New York 115 kV transmission system was exposed to approximately 628,000 danger trees. Our research reveals that the utility forest will increase to approximately 1.9 million trees between the years 2004 and 2019. Since most of tree-caused service interruptions are caused by trees outside the ROW, this area is targeted for reduction of danger trees. Because the utility forest is increasing in area, the current danger tree program, which targets identifiable hazard trees, will not keep pace with the increase in the number of danger trees. Our data since 1996 indicates that 68% of trees that fail and cause an outage event could not have been identified as hazard trees. Therefore, it is necessary to focus on danger trees to effect an improvement in reliability.

<u>Name of Respondent:</u>
Dawn Travalini

<u>Date of Reply:</u>
February 23, 2010

Niagara Mohawk Power Corp
New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

Interruption & Disturbance System Event	Incident Report No.	Circuit Identification	Circuit Name	Outage Date/Time	Restore Date/Time	Storm?	Loss of Supply - Customers Interrupted	Lost Customer Minutes	Weather	Calendar Year	Sub-Region	Division
202355		T1100	Dunkirk - Falconer #162	1/8/05 15:35	1/8/05 15:36	N				2005	WSW	Western
208985		T1280	Gardenville - Homer Hill #152	4/2/05 19:49	4/2/05 19:50	Y				2005	WF	Western
209166		T1080	Dunkirk - Falconer #160	4/3/05 0:00	4/4/05 12:50	Y	11,524	57,620		2005	WSW	Western
209125		T1950	Gardenville - Homer Hill #151	4/3/05 9:42	4/3/05 23:30	Y	1	77		2005	WF	Western
215508		T5810	Ticonderoga - Republic #2	6/9/05 18:42	6/10/05 10:01	N	4,452	4,091,388		2005	ENE	Eastern
217871		T1550	Lockport - Mortimer #114	7/8/05 15:33	7/8/05 15:34	N				2005	WG	Western
219982		T1280	Gardenville - Homer Hill #152	7/26/05 17:38	7/27/05 17:47	Y	3,100	83,700		2005	WF	Western
219980		T1080	Dunkirk - Falconer #160	7/26/05 18:21	7/28/05 15:00	Y	11,527	314,029		2005	WSW	Western
225694		T1340	Homer Hill - Bennett Road #157	9/29/05 8:56	9/30/05 14:03	N	6,836	79,248		2005	WSW	Western
225717		T3280	McIntyre - Colton #8	9/29/05 12:22	9/30/05 18:27	N				2005	CN	Central
228107		T5270	Inghams - Stoner #9	10/19/05 19:39	10/20/05 19:26	N	10,328	888,208		2005	ENE	Eastern
231048		T1100	Dunkirk - Falconer #162	11/9/05 17:10	11/10/05 15:27	N	1,374	8,244		2005	WSW	Western
232948		T3210	Lake Colby - Lake Placid #3	11/29/05 8:34	11/29/05 15:26	Y	1,615	218,300		2005	CN	Central
232951		T3170	Colton - Malone #3	11/29/05 11:38	11/29/05 19:57	Y	555	33,855		2005	CN	Central
239946		T1170	Falconer - Homer Hill #154	2/17/06 7:26	2/18/06 14:28	Y	1	6	Rain - Heavy; Wind - Severe (55-73 mph); 49F	2006	WSW	Western
239781		T5690	Rotterdam - New Scotland #19	2/17/06 10:20	2/18/06 18:41	Y			Wind - Severe (55-73 mph)	2006	EC	Eastern
240240		T5810	Ticonderoga - Republic #2	2/17/06 11:25	2/17/06 21:54	Y	4,268	2,658,964		2006	ENE	Eastern
239840		T5750	Spier - Rotterdam #1	2/17/06 12:02	2/18/06 7:31	Y	18,900	21,320,000	Rain - Heavy; Wind - Severe (55-73 mph);	2006	ENE	Eastern
239842		T5760	Spier - Rotterdam #2	2/17/06 12:06	2/18/06 7:07	Y	19,855	22,655,000		2006	ENE	Eastern
239829		T5390	Meco - Rotterdam #10	2/17/06 15:08	2/19/06 9:22	Y			Wind - Severe (55-73 mph); 30F	2006	EC	Eastern
245301		T5880	Warrensburg - Scofield Road #10	5/24/06 15:34	5/25/06 21:03	N	3,496	279,680	Fair; Calm to light wind (0-12 mph); 65F	2006	ENE	Eastern
255890		T3140	Colton - Browns Falls #1	9/24/06 10:44	9/24/06 18:18	N	2,611	28,721	Rain - Heavy; Wind - Mild (13 - 31 mph); 65F	2006	CN	Central
256679		T1660	Niagara - Gardenville #180	10/13/06 4:50	10/13/06 18:00	Y	2,713	8,139	Freezing rain or sleet; Calm to light wind (0 - 12 mph); 32F	2006	WF	Western
		T1500	Lockport - Batavia #108	10/13/06 5:01	10/15/06 12:15	Y	3,900	7,800		2006	WG	Western
		T1550	Lockport - Mortimer #114	10/13/06 6:02	10/16/06 1:48	Y	1	642		2006	WG	Western
256689		T6020	Walck Road - Huntley #133	10/13/06 9:35	10/14/06 18:25	Y			Snow - Wet; Wind - Mild (13 - 31 mph); 33F	2006	WF	Western
		T1660	Niagara - Gardenville #180	10/13/06 19:51	10/14/06 1:50	Y				2006	WF	Western
256800		T3210	Lake Colby - Lake Placid #3	10/20/06 19:59	10/21/06 1:26	N	1,713	164,679	Freezing rain or sleet; Calm to light wind (0 - 12 mph); 33F	2006	CN	Central
256942		T1820	Packard - Huntley #130	10/28/06 23:17	10/29/06 18:20	Y	5,064	15,192	Rain - Light to moderate; Wind - Mild (13 - 31 mph); 36F	2006	WF	Western
257407		T1160	Falconer - Homer Hill #153	12/1/06 14:55	12/4/06 20:46	Y	1	860	Rain - Light to Moderate;Major Storm; 48F	2006	WSW	Western
257408		T1170	Falconer - Homer Hill #154	12/1/06 14:55	12/6/06 15:25	Y	1	860	Rain - Light to Moderate;Major Storm; 48F	2006	WSW	Western

New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)												
Interruption & Disturbance System Event	Incident Report No.	Circuit Identification	Circuit Name	Outage Date/Time	Restore Date/Time	Storm?	Loss of Supply - Customers Interrupted	Lost Customer Minutes	Weather	Calendar Year	Sub-Region	Division
257443		T6060	Mohican - North Troy #3	12/2/06 6:52	12/2/06 17:28	Y	2,576	110,768	Fair; wind - Mild (13 - 31 mph); 40F	2006	ENE	Eastern
257885		T5440	Mohican - Butler #18	1/15/07 9:08	1/16/07 21:49	Y	5,377	205,339	Freezing Rain or Sleet; Calm to light wind (0 - 12 mph); 28F	2007	ENE	Eastern
258829		T5820	Ticonderoga - Hague Road #4	4/15/07 19:21	4/18/07 12:59	N			Snow - West; Major Storm	2007	ENE	Eastern
259283		T1610	Mortimer (Sta.82) - Quaker (Sta.121) #23	5/15/07 21:44	5/16/07 7:30	N			Rain - light / moderate, Thunderstorms, 60F	2007	WG	Western
259589		T1610	Mortimer (Sta.82) - Quaker (Sta.121) #23	6/3/07 1:12	6/3/07 10:03	N			Fair; Mild	2007	WG	Western
259808		T1090	Dunkirk - Falconer #161	6/13/07 13:52	6/14/07 12:34	N	2,848	50,707	Fair	2007	WSW	Western
259869		T4220	Porter - Schuyler #13	6/19/07 16:27	6/20/07 2:15	N			Rain - heavy	2007	CMV	Central
259877		T1160	Falconer - Homer Hill #153	6/19/07 18:19	6/21/07 8:25	N	1	40	Rain - heavy	2007	WSW	Western
260041		T5350	Maplewood - Menands #19	6/27/07 17:39	6/28/07 23:19	N			Extreme hot or cold, temp 90	2007	EC	Eastern
260358		T5880	Warrensburg - Scofield Road #10	7/10/07 19:10	7/11/07 4:30	Y	1,618	967,564	Major Storm	2007	ENE	Eastern
260358		T5770	Spier - West #9	7/10/07 19:10	7/12/07 1:31	Y			Major storm	2007	ENE	Eastern
261354		T1580	Mortimer - Golah #110	9/11/07 22:07	9/12/07 8:12	N			Rain-heavy	2007	WG	Western
262616		T3340	Taylorville - Moshier #7	12/29/07 8:03	12/29/07 8:08	N	258	1,290	Wind -Strong	2007	CN	Central
262720		T3340	Taylorville - Moshier #7	1/9/08 9:59	1/9/08 23:59	N	256	222,464	Rain Wind Severe	2008	CN	Central
262800		T1550	Lockport - Mortimer #114	1/13/08 13:25	1/13/08 13:26	N			Fair	2008	WG	Western
262801		T1550	Lockport - Mortimer #114	1/13/08 13:43	1/14/08 17:37	N	1	3	Fair	2008	WG	Western
262990		T1280	Gardenville - Homer Hill #152	1/30/08 4:34	1/30/08 23:41	Y	4,116	185,220	Severe Winds, Rain/Sleet/Ice	2008	WF	Western
263001		T1900	Valley (Sta. 44) - Ischua Switch #158	1/30/08 6:17	1/30/08 10:07	Y	3,046	700,580	Severe Winds, Rain/Sleet/Ice	2008	WSW	Western
263163		T1300	Gardenville - Seneca #82	2/6/08 16:53	2/13/08 8:40	N	2,080	199,680	Freezing Rain/Wind	2008	WF	Western
263187		T1390	Huntley - Gardenville #39	2/6/08 20:08	2/7/08 17:02	Y			Freezing Rain/Wind	2008	WF	Western
263504		T2140	Curtis Street - Teall #13	3/8/08 21:23	3/8/08 21:29	N	12,020	72,120	Snow-wet	2008	CC	Central
266706		T1170	Falconer - Homer Hill #154	6/6/08 8:30	6/6/08 16:16	N	2	534	Fair	2008	WSW	Western
267156		T2120	Coffeen - Black River - Lighthouse Hill #5	6/10/08 11:40	6/11/08 18:32	Y	5,611	28,055	TStorms	2008	CN	Central
267179		T3140	Colton - Browns Falls #1	6/10/08 12:26	6/11/08 18:42	Y	2,649	4,807,935	TStorms	2008	CN	Central
267182		T3150	Colton - Browns Falls #2	6/10/08 12:50	6/11/08 20:16	Y			TStorms	2008	CN	Central
267503		T3160	Colton - Townline #9	6/10/08 12:53	6/10/08 23:39	Y	5	3,230	TStorms	2008	CN	Central
267184		T3170	Colton - Malone #3	6/10/08 13:02	6/11/08 19:25	Y	2,762	196,102	TStorms	2008	CN	Central
267216		T6060	Mohican - North Troy #3	6/10/08 20:21	6/11/08 18:18	Y	2,458	125,358	TStorms	2008	ENE	Eastern
276966		T1820	Packard - Huntley #130	9/14/08 21:19	9/15/08 2:33	Y	5,065	50,650	Rain,High Winds	2008	WF	Western
277026		T1900	Valley (Sta. 44) - Ischua Switch #158	9/14/08 22:58	9/15/08 8:16	Y	1,372	760,088	Rain,High Winds	2008	WSW	Western
276990		T2560	Sleight Road - Auburn (State St.) #3	9/15/08 1:53	9/15/08 19:01	Y	1	963	Rain,High Winds	2008	WG	Western
276989		T2120	Coffeen - Black River - Lighthouse Hill #5	9/15/08 3:06	9/15/08 23:43	Y	6,618	19,854	Rain,High Winds	2008	CN	Central
276991		T3340	Taylorville - Moshier #7	9/15/08 3:33	9/15/08 21:43	Y	256	277,248	Rain,High Winds	2008	CN	Central
277347		T6070	Spier - Mohican #7	9/18/08 10:09	9/18/08 15:45	N			Fair	2008	ENE	Eastern
282780		T5940	Feura Bush - North Catskill #2	12/12/08 2:13	12/12/08 21:29	Y			Ice/Snow	2008	EC	Eastern
282781		T5760	Spier - Rotterdam #2	12/12/08 2:38	12/13/08 0:10	Y	14,957	29,914	Ice/Snow	2008	ENE	Eastern
282785		T5690	Rotterdam - New Scotland #19	12/12/08 3:34	12/13/08 12:41	Y			Ice/Snow	2008	EC	Eastern
282786		T5080	Lafarge Bldg Matls - Pleasant Valley #8	12/12/08 3:46	12/13/08 19:55	Y	750	779,250	Ice/Snow	2008	EC	Eastern
284867		T1390	Huntley - Gardenville #39	12/28/08 8:22	12/28/08 17:37	Y	37	111	Fair, Severe Wind	2008	WF	Western
284872		T1340	Homer Hill - Bennett Road #157	12/28/08 9:50	12/30/08 13:38	Y	424	72,928	Fair, Severe Wind	2008	WSW	Western
284878		T1450	Huntley - Lockport #37	12/28/08 10:23	12/30/08 22:08	Y			Fair, Severe Wind	2008	WF	Western

New York 115 kV Sustained Vegetation-Caused Outages (2005 - 2009)

Interruption & Disturbance System Event	Incident Report No.	Circuit Identification	Circuit Name	Outage Date/Time	Restore Date/Time	Storm?	Loss of Supply - Customers Interrupted	Lost Customer Minutes	Weather	Calendar Year	Sub-Region	Division
287677		T1280	Gardenville - Homer Hill #152	2/12/09 11:16	2/13/09 18:49	Y	4,166	41,660	Wet Snow, Strong Winds	2009	WF	Western
296317	21124-0	T1530	Lockport - Mortimer #111	6/9/09 10:37	6/9/09 17:29	N	6,721	20,163	Fair, Mild Wind	2009	WG	Western
301688	21154-0	T2560	Sleight Road - Auburn (State St.) #3	7/26/09 15:03	7/26/09 17:15	N			Heavy Rain, Thunderstorms	2009	WG	Western
303052	21163-1	T1080	Dunkirk - Falconer #160	8/9/09 23:27	8/10/09 11:45	Y	10,959	397,173	Rain-heavy/Thunderstorms	2009	WSW	Western
303139	21164-0	T1270	Gardenville - Dunkirk #142	8/10/09 12:06	8/10/09 18:43	Y			Fair/Mild wind	2009	WF	Western
303598	21173-1	T1950	Gardenville - Homer Hill #151	8/22/09 3:26	8/22/09 13:47	N	2	126	Fair/Calm to light wind	2009	WF	Western
304212	21182-0	T2560	Sleight Road - Auburn (State St.) #3	10/7/09 15:49	10/8/09 1:29	N	1	60	Rain-light/Strong wind	2009	WG	Western
304452	21183-0	T1170	Falconer - Homer Hill #154	10/29/09 10:28	10/30/09 15:27	N	1	32	Fair/Calm to light wind	2009	WSW	Western
304907	21197-1	T1260	Gardenville - Dunkirk #141	12/9/09 6:29	12/9/09 6:30	Y			Dry Snow, Strong Wind	2009	WF	Western
304908	21197-1	T1280	Gardenville - Homer Hill #152	12/9/09 6:44	12/9/09 11:11	Y	4,187	25,122	Dry Snow, Strong Wind	2009	WF	Western
304909	21197-1	T1600	Mortimer - Pannell Road #25	12/9/09 8:11	12/9/09 14:12	Y			Dry Snow, Strong Wind	2009	WG	Western
304906	21197-1	T1260	Gardenville - Dunkirk #141	12/9/09 8:13	12/9/09 8:14	Y			Dry Snow, Strong Wind	2009	WF	Western
304913	21197-1	T1260	Gardenville - Dunkirk #141	12/9/09 9:44	12/9/09 18:22	Y	26,968	678,187	Dry Snow, Strong Wind	2009	WF	Western

Date of Request: February 11, 2010 Request No. DPS-25(RAV-14)
Due Date: February 22, 2010

NMPC Req. No. ____
Case No.10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates
Request for Information

FROM: Robert Visalli
TO:

Request:
For former NMPC employee # 100028397, please provide the following information:
A. The date of his retirement and salary at time of retirement.
B. Indicate if he was a VERO employee. If so, provide the costs of his being VERO'ed by type of cost.
C. From the date of retirement up to the present time, please provide in an Excel spreadsheet the following information by calendar year:
1. Number of hours he worked for the Company as a contracted employee;
2. Amounts paid to him for his contractor services;
3. Amounts paid to him for air travel expenses to and from Syracuse, along with the number of roundtrip flights;
4. Amounts paid to him for room and board;
5. All other amounts paid to him;
6. Total costs paid to him.
D. Indicate whether the above costs were charged to capital or expense, along with the reason for such accounting.
E. Indicate the date he first performed contractor services for the Company.
F. Indicate if he is still a contracted employee; if not, indicate the last date that he performed contractor services for the Company.

Response:

A. The former employee's date of retirement was June 1, 2002. His salary at the time of retirement was $76,100.
B. Yes, this individual retired under a VERO. The cost to VERO this employee was $309,138 for pension and $2,450 for medical.
C. Please see Attachment 1 (RAV-14_Attachment_1_Employee 100028397 Contract Expenses).
D. The costs indicated in request C are charged to capital because he was contracted to assist in the closeout of capital work orders. As a result, all costs incurred were charged to capital.
E. The date this individual first performed contractor services for National Grid was February 24, 2003.
F. Yes, this individual is still a contracted employee.

Form 103

Name of Respondent:

Pat Michels

Date of Reply:

2/22/2010

Form 103

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employee # 100028397

Agency	CPS	CPS	CPS	CPS	CPS	PrO Unlimited	PrO Unlimited	PrO Unlimited	PrO Unlimited	PrO Unlimited
Expenses	**2002**	**2003**	**2004**	**2005**	**2006**	**2006**	**2007**	**2008**	**2009**	**2010 *** **
Hours worked as a contractor *	0			2,603	1,985	176	2,019	1,811	771	58.5
Amount paid as a contractor	0.00	4,171.28	134,566.12	95,247.43	79,182.55	6,439.84	73,856.92	69,924.50	29,176.39	4,095.00
Amount paid for air travel	0.00					1,088.00	15,545.00	11,714.10	4,805.50	207.90
Amount paid for room and board	0.00					1,061.07	13,719.21	9,537.49	3,896.16	210.53
All other amounts paid **	0.00			39,540.53	39,698.07	864.30	13,536.96	10,476.74	3,988.97	118.25
Total amount paid	0.00	4,171.28	134,566.12	134,787.96	118,880.62	9,453.21	116,658.09	101,652.83	41,867.02	4,631.68
Number of round trip flights to/from Syracuse *	0					2	38	21	10	0

* CPS could not provide hours worked from 2003 and 2004 due to a change of computer systems. CPS also could not provide the number of round trip flights.

** For CPS, amounts include all expenses (air travel, room and board, other expenses). For PrO Unlimited, amounts include parking, gas, car rental, etc.

*** Information available through 2/15/10.

Date of Request: February 12, 2010
Due Date: February 22, 2010

Request No. RAV-19
NMPC Req. No. NM 33 DPS 30

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Maureen Heaphy

Request:

On page 20 of your pre-filed testimony, you state that "the financial goals reflected in National Grid's variable pay Plan are not tied to the financial performance of Niagara Mohawk; they are tied to the financial performance of National Grid. As a consequence, it is not the case, as it **apparently** was in the National Fuel decision, that Niagara Mohawk must achieve savings that are not reflected in the revenue requirement in order for National Grid to achieve its enterprise-wide financial goals." [emphasis added] Regarding this claim, please provide documented proof that National Fuel's 1990 Incentive Plan was tied solely to the performance of NFG's regulated operations in NYS.

Response:

Ms. Heaphy has not testified that National Fuel's 1990 Incentive Plan "was tied solely to the performance of NFG's regulated operations in NYS." In its July 19, 1991 Order in *National Fuel* Case 90-G-0734, the Commission determined that "it is only reasonable to expect" that if the goals underlying National Fuel's variable compensation plan were met, there would be "cost savings, which have not been reflected in the revenue requirement." Ms. Heaphy assumes that when the Commission referred to "cost savings" and "the revenue requirement" it was referring to cost savings that would be properly attributable to National Fuel's regulated operations in New York State and the revenue requirement arising from those jurisdictional operations. It is Ms. Heaphy's testimony that it is not the case that Niagara Mohawk must achieve savings that are not reflected in Niagara Mohawk's revenue requirement in order for National Grid to achieve its enterprise-wide financial goals. Thus, it would not be appropriate for the Commission to conclude, as it did in *National Fuel*, that if National Grid were to attain the financial goals set forth in its variable compensation plan, it would be reasonable to expect that Niagara Mohawk had achieved savings that are not reflected in its regulated revenue requirement.

Name of Respondent: Date of Reply:

Kenneth Maloney & Maureen Heaphy February 18, 2010

Date of Request: February 12, 2010
Due Date: February 22, 2010

Request No. RAV-20
NMPC Req. No. NM 34 DPS 31

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Maureen Heaphy

Request:
A. On page 29 of your pre-filed testimony, you discuss implementation of cost containment measures in the Company's disability benefit program.

Please indicate when each of these measures took effect. Please provide all supporting internal memos, correspondence, or other documentation that shows the implementation dates.

Explain how the rate years' forecasts reflect these cost containment measures.

B. On page 30 of your pre-filed testimony, you discuss bringing all non-union employees under a common benefit program across National Grid, which helped stabilize and reduce administrative costs through economies of scale. These changes were effective January 1, 2009.

Please quantify the reduced administrative costs that occurred through the economies of scale. Include the cost benefit analysis which led the Company to make these changes.

Since this change to reduce costs took place part way through the historic test year, show how the Company's rate years' forecasts reflect annualization of these cost reduction measures. If an annualizing adjustment was not made, fully explain why not.

C. On pages 30-31 of your pre-filed testimony, you discuss a number of changes in the Company's medical, dental, and life insurance programs to reduce costs that were made during 2009.

Please indicate when each of these measures took effect; include supporting internal memos or other correspondence that shows the implementation dates.

Please quantify the reduced costs associated with each change. Include the cost benefit analysis that led the Company to make these changes.

Explain how the rate years' forecasts reflect full annualization of these cost reduction measures. If an annualizing adjustment was not made, fully explain why not.

Form 103

Response:

A) The cost containment measures in the Company's disability benefit programs were first implemented in June 2002 with the introduction of Matrix as the third party administrator for both short and long-term disability benefits for National Grid New England employees. The relationship with Matrix was expanded in years 2003 and 2004 to incorporate Niagara Mohawk Power Corporation employees; non-union employees were added as of January 2003 and union employees were added as of February 2004. The documentation that shows the implementation dates is attached as Attachment 1 DPS-31 (RAV-20) and Attachment 2 DPS-31 (RAV-20). The benefits resulting from the implementation of these cost containment measures are reflected in the ongoing expense levels that carry forward to the rate years.

B) and C) In 2008, the Company completed a review of the benefit plans and programs that were in place for non-union employees at both legacy National Grid and legacy KeySpan. As a result of this review, the Company was able to align the health and welfare benefit offerings and develop a common benefits platform that was implemented for all non-union employees across the United States as of January 1, 2009. The benefit changes and any associated impact on costs were reviewed by benefit plan at a total company level, separated by legacy National Grid and legacy KeySpan. All potential cost reductions/savings were reviewed in the aggregate and administrative costs were not separately identified.

The changes in the Company's non-union medical, dental and life insurance programs addressed in the pre-filed testimony were part of the alignment mentioned above and became effective as of January 1, 2009. The implementation date for these changes was communicated to employees in October 2008 during the Open Enrollment Process. A copy of the 2009 Benefits Enrollment Guide that was distributed to all non-union employees in October 2008 is attached as Attachment 3 DPS-31 (RAV-20).

The anticipated cost reductions associated with the benefit changes in medical, dental and life insurance programs for legacy National Grid, which took effect on January 1, 2009 are as follows:

Benefit Plan	**Anticipated Reduction in Costs**
Medical (including Rx) and Dental Plans	$ 3.9M
Life Insurance Plan	$ 0.5M

The cost benefit analyses for the changes in the healthcare plans are attached as Attachment 4 DPS-31 (RAV-20) and Attachment 5 DPS-31 (RAV-20).

Since the benefit changes were effective on January 1, 2009, the test year reflected 9/12th's of the reduced costs associated with these changes.

For the life insurance benefit expense, the rate year forecast reflects full annualization of the cost reduction associated with the reduced coverage level. An annualizing adjustment of $41,801 was made to reflect the reduced costs for the remaining 3/12th's using the reduced coverage level and the cost per $1,000 of coverage.

For the healthcare benefits expense, since the medical, inclusive of prescription drugs, and dental plans are self insured, the projected cost reductions were based on varying assumptions (i.e. claims experience, medical trend, plan enrollment/migration from existing plans); and the actual cost reductions for the period January 1, 2009 through September 30, 2009 attributable to the benefit changes were not quantifiable. As such, the historical test year expense level was not adjusted.

If the Company was to provide an estimate of an annualizing adjustment for the remaining 3/12's of healthcare benefits expense for the historic test year, it would be approximately $312,147 based on the same methodology used above for the life insurance benefit expense. This adjustment is calculated with the caveat that the level of savings was calculated using varying assumptions for claims experience, plan participation and coverage levels.

Name of Respondent:	Date of Reply:
Lori Santoro	February 22, 2010

Date of Request: February 12, 2010
Due Date: February 22, 2010

Request No. RAV-20 Supplemental
NMPC Req. No. NM 34 DPS 31

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Maureen Heaphy

Original Request:

C. On pages 30-31 of your pre-filed testimony, you discuss a number of changes in the Company's medical, dental, and life insurance programs to reduce costs that were made during 2009.

Please indicate when each of these measures took effect; include supporting internal memos or other correspondence that shows the implementation dates.
Please quantify the reduced costs associated with each change. Include the cost benefit analysis that led the Company to make these changes.
Explain how the rate years' forecasts reflect full annualization of these cost reduction measures. If an annualizing adjustment was not made, fully explain why not.

Supplemental Request:
In Part C of this IR, I specifically asked if a normalizing adjustment had been made to fully reflect annualization of the cost reduction measures. I also specifically asked if an annualizing adjustment was not made, fully explain why not. In response, the Company states "if the Company was to provide an estimate of an annualizing adjustment it would be approximately $312K............".

Nowhere in the response does the Company explain why it did not make the normalizing adjustment or if it agrees/disagrees that a normalizing adjustment should be made. Would you please clarify this response?

Supplemental Response:
C. For life insurance benefit expense, an annualizing adjustment of $41,801 was made to reflect the reduced costs for the $3/12^{th}$'s of the historic test year since the benefit change became effective on January 1, 2009. This adjustment was calculated based on the level of savings associated with reducing the coverage amount from two times base salary to one times base salary.

For healthcare benefits expense, inclusive of prescription drugs and dental plans, no annualizing adjustment was made to the historic test year. Although the benefit changes also became effective on January 1, 2009, as the Company stated in its original response to RAV-20, because these plans are self-insured and the costs are based on varying assumptions (i.e. claims experience, medical trends, plan enrollment/migration from existing plans), the Company felt that these savings were not quantifiable at the time of the filing. Thus, no annualizing adjustment was made. The Company does agree however that if the level of savings were known and measurable, an adjustment to the historic test year expense level would be warranted.

In the initial response to RAV-20, the Company provided an estimate ($312K of which approximately $227K is O&M) of an annualizing adjustment based on the same methodology used to calculate the savings for group life insurance (See Attachment 1); however, the Company does not believe that this adjustment is likely to be representative of actual savings because of the impacts of likely variations in claims experience, plan participation and coverage levels.

To support this position, the Company performed an analysis and reviewed the healthcare benefits expense for calendar year 2009, which should reflect a full year of savings, and compared it to the expense level for the twelve month period ended September 30, 2009 (See Attachment 2). The expense level for calendar year 2009 was nearly the same as the level of healthcare expense for the 12 months ended September 30, 2009. This further demonstrates that there are no additional savings to be normalized from the historic test year.

However, while performing this analysis, the Revenue Requirement Panel discovered that the capitalization rate used in the historic test year was incorrect. The rate used in the historic test year was 33.02% and should have been 35.64%. This results in lower healthcare expenses of $667,000 for the historic test year and $688,000, $701,000, and $714,000 for each respective rate year. The capitalization rate change will also reduce expense levels for some other benefits as well. For all affected benefits, the Company estimates a reduction of $1.014 million in the historic test year, and $1.047 million, $1.066 million, and $1.086 million in each respective rate year. All benefits affected will be adjusted at the time the Company submits Corrections and Updates in this proceeding.

<u>Name of Respondent:</u>
Maureen Heaphy
James Molloy

<u>Date of Reply:</u>
March 16, 2010

Adjustment to Remove Savings from Benefits Expense

						Life Insurance	Medical & Dental Incl Prescrip Drugs
Total Savings for Non-Union Employees (Annual)						522,268	3,900,000
Quarter of a Year or 25% of Annual Savings						130,567	975,000
Less Capitalized Portion	35.64%					46,534	347,490
O&M Portion of Savings						84,033	627,510
% of Total NIMO Labor to Total National Grid Labor					0.2959		
% of Savings that should be allocated to Niagara Mohawk						24,865	185,680
% of Total Service Company Labor to Total National Grid Labor					0.158981		
% of Savings that should be allocated to Service Company						20,758	155,006
% of Savings that should be allocated from Service Company to NIMO					0.565	11,728	87,578
						36,593	273,259
		O&M	83%	HTY ADJ	ELEC	30,373	226,805
		Capital				11,428	85,342
		Total NIMO Savings				41,801	312,147

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Operating Expenses by Component
Health Care - Expense Type B03
($000's)

	Column	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Line	Calendar Year Ended December 31, 2009 (per books)			Adjustments to Normalize Historic Test Year			Calendar Year Ended December 31, 2009 (as Adjusted)		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
Provider Company:										
Niagara Mohawk Power Corp.	1	$ (18,699.3)	$ (15,508.9)	$ (3,190.4)	$ 37,835.2	$ 31,391.7	$ 6,443.5	$ 19,135.8	$ 15,882.7	$ 3,253.1
National Grid USA Service Co.	2	5,466.3	4,790.6	675.7	147.7	(131.0)	278.7	5,614.0	4,659.6	954.4
All Other Companies	3	41,064.6	33,847.6	7,217.0	(39,203.2)	(32,302.6)	(6,900.6)	1,861.5	1,545.0	316.4
Total	4	$ 27,831.6	$ 23,129.3	$ 4,702.3	$ (1,220.3)	$ (1,041.9)	$ (178.4)	$ 26,611.3	$ 22,087.4	$ 4,523.9
Operation:										
Production Expenses		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power Production Expenses		-	-	-	-	-	-	-	-	-
Natural Gas Storag, Terminaling and Processing Exp.		-	-	-	-	-	-	-	-	-
Transmission Expenses	5	14.9	14.9	-	(14.9)	(14.9)	-	-	-	-
Regional Market Expenses		-	-	-	-	-	-	-	-	-
Distribution Expenses	6	54.3	28.7	25.7	(54.3)	(28.7)	(25.7)	-	-	-
Customer Accounts Expenses	7	75.6	46.2	29.3	-	-	-	75.6	46.2	29.3
Customer Service and Informational Expenses		-	-	-	-	-	-	-	-	-
Sales Expenses	8	33.5	3.5	30.0	-	-	-	33.5	3.5	30.0
Administrative & General Expenses	9	27,588.8	23,022.5	4,566.3	(1,086.6)	(984.8)	(101.7)	26,502.3	22,037.7	4,464.6
Sub Total	10	$ 27,767.1	$ 23,115.8	$ 4,651.3	$ (1,155.8)	$ (1,028.4)	$ (127.4)	$ 26,611.3	$ 22,087.4	$ 4,523.9
Maintenance:										
Transmission Expenses	11	$ 1.3	$ 1.3	$ -	$ (1.3)	$ (1.3)	$ -	$ -	$ -	$ -
Distribution Expenses	12	54.3	3.3	51.0	(54.3)	(3.3)	(51.0)	-	-	-
Administrative & General Expenses	13	9.0	9.0	-	(9.0)	(9.0)	-	-	-	-
Sub Total	14	$ 64.5	$ 13.5	$ 51.0	$ (64.5)	$ (13.5)	$ (51.0)	$ -	$ -	$ -
TOTAL	15	$ 27,831.6	$ 23,129.3	$ 4,702.3	$ (1,220.3)	$ (1,041.9)	$ (178.4)	$ 26,611.3	22,087.4	$ 4,523.9
Historic Test Year Healthcare Exp as filed with Cap % adj from 33.02% to 35.64%								26,611.6	22,087.5	4,524.1
Increased Costs for Cal 09 Healthcare Expense								(0.3)	(0.1)	(0.2)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Operating Expenses by Component
Health Care - Expense Type B03
($000's)

			Provider Company	Total	Electric	Gas
	Explanation of Adjustments:					
Lines	Sheet 1	Adjustments: (to normalize Historic Year)				
1		To adjust capitalization % - 37.75%	Niagara Mohawk Power Corp.	$ (1,345.2)	$ (1,116.48)	$ (228.68)
2		To adjust the electric/gas allocation to 83%/17% respectively	Niagara Mohawk Power Corp.	-	(11.5)	11.5
3		To adjust accrual that should have been derived from Co. 36	Niagara Mohawk Power Corp.	39,203.2	32,538.6	6,664.5
4		Consumer Advocates Normalized	Niagara Mohawk Power Corp.	(22.9)	(19.0)	(3.9)
		To adj amount allocated from Company 99 - 25.24%	National Grid USA Service Co.	147.7	122.6	25.1
5		To adjust the electric/gas allocation to 83%/17% respectively	National Grid USA Service Co.	-	(253.6)	253.6
6		To adjust the electric/gas allocation to 83%/17% respectively	All Other Companies	-	236.0	(236.0)
7		To adjust accrual that should have been derived from Co. 36	All Other Companies	(39,203.2)	(32,538.6)	(6,664.5)
8		TOTAL		$ (1,220.3)	$ (1,041.9)	$ (178.4)

Date of Request: February 17, 2010
Due Date: March 1, 2010

Request No. RAV-22
NMPC Req. No. NM 39 DPS 36

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: David Lister

Request:

On page 13 of your pre-filed direct testimony, you discuss the projected in-service date of the Back Office Project (BOP). Therein, you state that the Company is not proposing recovery of any costs associated with the BOP in 2011. You further state that the Company is still "**providing customers with the synergy savings credit associated with the Back Office Project beginning in the rate year ending December 31, 2011**" (emphasis added).

A. Regarding this statement, please explain the type of synergy savings credits associated with the BOP that customers are receiving in the RYE 12/31/11.

B. Please explain why customers are entitled to these synergy savings credits in the RYE 12/31/11; include references to specific clauses in joint proposals, settlement agreements, etc, if applicable.

C. How much in synergy savings credits are customers receiving in the RYE 12/31/11? Include supporting workpapers and calculations as to how the amounts were derived, and show where and how such credits are reflected in the Company's pre-filed exhibits.

On page 14 of your pre-filed direct testimony, you state that the BOP is a "**replacement of the current Finance, Human Resources and Supply Chain systems in the US**" (emphasis added).

D. Regarding this statement, please provide a breakdown of all historic test year (HTY) costs associated with the current Finance, Human Resources, and Supply Chain systems in the US, in total, including both NMPC's electric and gas allocations.
E. Fully explain how and show where these HTY costs were eliminated from the RYE 12/31/12 forecast since the BOP system will replace these current systems.

Response:

A. Since the Company based the synergy savings estimate in 2011 on the full synergies being realized by the Rate Year, any synergies and the savings associated with a new ERP system are included in the synergy savings estimate. These savings are in the rate year.

B. There is no requirement that entitles customers to these synergy savings before they are realized. However, the Company has provided the benefit to customers.

C. Customers are receiving $3,128,364 in synergy savings credits in the RYE 12/31/11. Please refer to Attachment A for the supporting calculation and references to the Company's pre-filed exhibits.

D. Please refer to Attachment B.

E. The current Finance, Human Resources, and Supply Chain system in the US, also known as PeopleSoft ERP, appears on the books of NMPC as rent expense allocated from the Service Company. Please refer to the Rent Expense exhibit, Exhibit____(RRP-2), Schedule 8, Sheets 10 and 11, Line 9. Line 9 shows the historical test year costs for the PeopleSoft ERP system. PeopleSoft ERP was fully amortized as of September 2009; therefore, looking across Line 9 into Rate Years 2011, 2012, and 2013, the schedule shows no dollars have been included in the Rate Years for this project. Forecasted rent expense for the new BOP is shown on this same schedule at Line 18 in the Rate Years 2012 and 2013.

Name of Respondent:	Date of Reply:
James M. Molloy	February 23, 2010

Form 103

NIAGARA MOHAWK POWER CORPORATION
d/b/a National Grid
Case 10-E-0050
Attachment A to RAV-22
Sheet 1 of 1

RAV-22 Part C: Synergy Savings related to the US ERP Back Office Project

Line		Rate Year 2011	
1	US ERP BOP projected savings	$ 15,009,800	a
2	Prorated @ $200m/$246.917m	81.00%	b & c
3	Line 1 * Line 2	$ 12,157,770	
4	NiMo Electric allocation	24.93%	d
5	Line 3 * Line 4	$ 3,030,932	
6	Inflation	3.21%	e
7	Line 5 * (1+ Line 6)	**$ 3,128,364**	

a\ Per Exhibit ___(RRP-10) Workpaper to Exhibit __(RRP-2), Schedule 42, Workpaper 1, Sheet 6
b\ $200m = Per Exhibit __(RRP-2), Schedule 42, Sheet 5
c\ $246.917m = Exhibit ___(RRP-10) Workpaper to Exhibit __(RRP-2), Schedule 42, Workpaper 1, Sheet 10
d\ Per Exhibit __(RRP-2), Schedule 42, Sheet 4
e\ Per Exhibit __(RRP-7), Summary, Sheet 1

RAV-22 Part D: Historic Test Year costs associated with the US PeopleSoft ERP system

Work Order	9000027746
Work Order Descr	(All)

Sum of GL Act $				Business			
Expense Type	Expense Type Descr	Business Unit	Bus Unit Descr	Electric	Gas	Other	Grand Total
500	Rental/Lease Non-Real Estate	00004	Nantucket Electric Company	7,846.55			7,846.55
		00005	Massachusetts Electric Company	1,202,685.31			1,202,685.31
		00006	NE Hydro - Trans Electric Co	12,859.44			12,859.44
		00008	New England Hydro - Trans Corp	36,383.84			36,383.84
		00010	New England Power Company	168,551.18			168,551.18
		00020	New England Electric Trans Co	1,635.59			1,635.59
		00021	National Grid Trans Services	327.06			327.06
		00036	Niagara Mohawk Power Corp	1,991,217.62	407,822.16		2,399,039.78 a\
		00041	Granite State Electric Company	37,544.91			37,544.91
		00048	Narragansett Gas Company		246,257.46		246,257.46
		00049	Narragansett Electric Company	419,313.38			419,313.38
		00070	Wayfinder Group Inc.			61.11	61.11
		00071	Valley Appliance & Merchandise			413.72	413.72
Grand Total				**3,878,364.88**	**654,079.62**	**474.83**	**4,532,919.33**

				Segment Allocation				Business Unit
Expense Type	Expense Type Descr	Business Unit	Bus Unit Descr	Electric	Gas	Other	Grand Total	Allocation
500	Rental/Lease Non-Real Estate	00004	Nantucket Electric Company	100.00%	0.00%	0.00%	100.00%	0.17%
		00005	Massachusetts Electric Company	100.00%	0.00%	0.00%	100.00%	26.53%
		00006	NE Hydro - Trans Electric Co	100.00%	0.00%	0.00%	100.00%	0.28%
		00008	New England Hydro - Trans Corp	100.00%	0.00%	0.00%	100.00%	0.80%
		00010	New England Power Company	100.00%	0.00%	0.00%	100.00%	3.72%
		00020	New England Electric Trans Co	100.00%	0.00%	0.00%	100.00%	0.04%
		00021	National Grid Trans Services	100.00%	0.00%	0.00%	100.00%	0.01%
		00036	Niagara Mohawk Power Corp	83.00%	17.00%	0.00%	100.00%	52.92%
		00041	Granite State Electric Company	100.00%	0.00%	0.00%	100.00%	0.83%
		00048	Narragansett Gas Company	0.00%	100.00%	0.00%	100.00%	5.43%
		00049	Narragansett Electric Company	100.00%	0.00%	0.00%	100.00%	9.25%
		00070	Wayfinder Group Inc.	0.00%	0.00%	100.00%	100.00%	0.00%
		00071	Valley Appliance & Merchandise	0.00%	0.00%	100.00%	100.00%	0.01%
Grand Total				**85.56%**	**14.43%**	**0.01%**	**100.00%**	**100.00%**

a\ agrees to Exhibit___(RRP-2), Schedule 8, Sheet 10, Line 9 "Test Year IS Rent Expense"

Date of Request: February 17, 2010
Due Date: March 1, 2010

Request No. RAV-27
NMPC Req. No. NM 44 DPS 41

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Infrastructure and Operations Panel

Request:

Regarding the Panel's pre-filed direct testimony on major storms at pages 23- 238, please provide the following information:
A. Fully explain why the Panel chose the 4.5 year period from April 2005 – August 2009 as the basis for determining the rate year forecast of "Incremental Deferred" storm costs. Why didn't the Company use 3 years? Why didn't the Company use 5 years? Why didn't the Company use entire approximate 7.75 years from the time the MJP first went into effect through the end of the historic test year?
B. What was the average "Incremental Deferred" storm cost for the period from February 1, 2002 – September 30, 2009? Include supporting calculations with all individual qualifying "Incremental Deferred" storms and related costs listed.
C. What is the Company's rationale for establishing the storm fund at 88% of the average "Incremental Deferred" storm costs? Why not establish the storm fund at 75% of the average "Incremental Deferred" storm costs? Why not establish the storm fund at 100% of the average "Incremental Deferred" storm costs?
D. Fully explain why the Company included two major storms with costs in excess of $45 million ($78.4 million for the October 2006 Buffalo storm and $47.4 million for the December 2008 ice storm) in the 4.5 year average used to make the rate year forecast. Why wasn't a normalization adjustment made to reflect the fact that it is not likely that two major storms of this cost magnitude will occur every 4.5 years?
E. Provide a list of all major storms over the past 20 years that had costs in excess of $20 million.
F. On page 236, for the types of major storm costs that are eligible for recovery through the Company's proposed storm fund, the Panel proposes using "the existing criteria established for deferral of storm costs."

Which criteria is the Panel referring to, the criteria set forth in the 2001 MJP or the criteria set forth in the 2007 Stipulation?

Specifically list each criteria the Company proposes using.

G. As set forth in Clause 1.2.4.5 of the MJP, the storm deferral account included a $2.0 million deductible for each major storm which "resolved any and all issues related to the Incremental Costs having the effect of reducing Niagara Mohawk's ongoing operating costs." Does the Company's proposed storm fund have a similar deductible? If so, how much is the deductible for each major storm and how was the amount determined? If not, fully explain why the Company does not agree that a similar deductible should not be put into effect in this case, assuming for purposes of this question only that the Commission were to agree to the Company's proposal to have a major storm fund.
H. Please provide a comprehensive list of every type of cost that the Company proposes to be included in the major storm fund account. Explain why each such cost is considered incremental to the base O&M allowances. Also indicate if there are any threshold levels that have to be met before the costs qualify for inclusion in the storm fund account (e.g., refer to the payroll tax threshold in storm Stipulation Clause 3.6.4 and to baseline internal employee count threshold in Stipulation Attachment 3). If there are such thresholds, identify the threshold levels and explain how each was derived / will be calculated. If there are no threshold levels, fully explain why not.
I. What is the maximum amount of time a cost can be incurred after a major storm but still be considered to be "major storm related?" For example, can a tree, said to be weakened / damaged by a major storm, be cut down one year after the storm and still be included in the storm fund account? Explain in full how you arrived at the maximum duration.
J. How much has the Company included in each of the three rate years for major storm expenses? Include exhibit / workpaper references.

Response:

A. The Panel chose a review from 1/1/2005 through 12/31/09, a five year period in preparation for this submittal. Exhibit IOP -11 Sheet 1 of 1, as well as page 234 of the testimony refer to a 4.5 year average which is the time frame between the first event of 2005 and the final event prior to year end of 2009. A storm occurred in December of 2009 which was not included in this review due to qualifying status of a deferral event being undetermined at that time. The five-year period was utilized as a reasonable period over which to consider storm data, particularly given the three-year period proposed in this case. Calculation of a storm fund based on a different period was not specifically considered.

B. The average annual "Incremental Deferred" storm cost for the period from February 1, 2002 through September 30, 2009 was $22.4 million. Attachment 1 (RAV-27_Attach 1_ Incremental Deferred) provides the support as requested.

C. The 88% proportion referred to in the request appears to be based on the 4.5 year period referenced in the testimony, which is also described in the response to part A, above. Available data at the time of the filing of the rate case for the five-year period for the period January 1, 2005 – December 31, 2009 results in annual average deferrable incremental storm costs of approximately $30 million, which is the requested storm fund amount.

D. The events happened to take place in the five-year review period. Severe events such as the October 2006 snow storm and December 2008 ice storm do occur from time to time in upstate New York within close proximity, and the proposed storm is intended to provide for such extraordinary events. As stated in testimony these types of events can adversely affect cash flow and impact payments which are required to be made to mutual assistance organizations, third party contractors, and suppliers. Reconciliation of these accounts is required to ensure the success of future assistance requests.

E. Attachment 2 provides a list of all known major storms over the past 20 years that had costs in excess of $20 million.

F. The Panel is referring to the criteria set forth in the 2007 Stipulation. The Company proposes $6 million to be included in base rates for National Grid storm restoration annually. Each major storm event includes a $2 million deductible.. After the $6 million major storm annual base allowance is reached in a calendar year, the Company would be allowed recovery through the storm fund of incremental major storm costs incurred in excess of the $2 million per event deductible. For storm fund recovery purposes, a major storm occurs when a period of severe weather results in outages in a region exceeding 10% of the region's customers and/or at least 1% of its customers experience interrupted service for at least 24 hours.

G. Yes, the storm fund proposal continues the same $2.0 million deductible for each major storm event.

H. The costs the Company proposes to be included in the major storm fund account are the same as utilized currently under the Storm Restoration Deferrals set forth in the 2007 Stipulation. These costs include:

- Incremental costs that represent payments to any affiliated company or companies separately from the portion of incremental costs that represents internal costs and costs paid to unaffiliated third-parties. The labor and/or expenses would not be required without the event.
- The portion of Niagara Mohawk cost of contractors that qualify as incremental costs shall be determined by application of the methodology set forth in the 2007 Stipulation.
- Material and supplies – required to support the storm effort in materials, not required without the event.
- Internal and external overtime costs – required due to event.
- Transportation costs (excluding Niagara Mohawk including pooled vehicles) – required due to the event.
- Payroll taxes on storm-related overtime for Company employees over an annual threshold of $241,800 as deferrable incremental costs.
- Lodging – required due to the event.
- Employee expenses (meals, mileage, unusual, etc.) – required due to the event.

All thresholds to be utilized are taken from the 2007 Stipulation.

I. The maximum time a cost could be incurred after a major storm and be considered "major storm related" would generally be 3-4 months from the end of the event restoration. Some costs may be incurred even later in the case of extraordinary circumstances. However, all costs would still be subject to audit, and Commission approval. For example, the December 2008 ice storm required follow up patrols and maintenance from January through March due to the extent of the severe damage incurred during the event. Experience in major events provides insight into complete restoration requirements, which may require surveys, tree trimming, and construction /maintenance of facilities. Depending on the geography and severity of damage, it is reasonable to expect 3-4 months to complete this work in some cases. There will also be events requiring additional efforts which should be communicated with Staff as they occur. It should also be noted there is a difference between when costs are incurred and invoicing, which could differ greatly. For example, invoices for mutual assistance, reconciling and verifying invoices, etc., may be received long after actual incurrence of the costs reflected in the invoices.

J. The Company has included $30.5 million for rate year 2011, $31.26 million for rate year 2012, and $32 million for rate year 2013 in major storm expenses. Please see attachment 3 for reference.

Name of Respondent:	Date of Reply:
Allen Chieco	March 1, 2010

Event	Total	Base Pay	Benefits	Bonus	Contractor	Emp Exp	Inventory	Other	Overtime	Sales & Use Tax	Transportation	Payroll Tax	Regional Disqual.	Storm Deduct
February 1, 2002 (55645)	932,000		514,857		4,383,021	474,195	300,854	-3,253,603	5,764,706	170,556	77,414			-7,500,000
March 9, 2002 (83110)	2,865,482		200,161		1,257,001	167,892	40,519	756,328	2,245,604	98,648	99,329			-2,000,000
April 4, 2003 (55823)	9,507,265		278,744		7,471,321	696,237	453,754	882,103	7,512,815	179,425	32,866			-8,000,000
Storm # 82950	576,960		140,024		643,056	100,412	6,075	111,057	1,571,541		4,795			-2,000,000
October 15, 2003 (82965)	1,231,941		184,359		750,453	137,265	8,816	54,790	2,069,124		27,134			-2,000,000
November 13, 2003 (82978)	4,794,922		303,741		2,348,249	285,400	14,000	426,593	3,408,989		7,950			-2,000,000
February 17, 2006	2,835,937	211,301	0	0	4,697,117	269,290	403,418	725,285	5,574,853	212,131	-275,480	6,040	-988,018	-8,000,000
October 12, 2006	78,435,181	1,192,183	0	0	54,352,783	515,542	3,350,333	3,448,355	13,558,504	3,162,529	223,741	631,210	0	-2,000,000
October 28, 2006	219,340	1,249,177	82,105	1,680	2,936,696	57,606	20,584	55,585	20,215	35,961	683	0	-2,240,952	-2,000,000
December 1, 2006	2,117,778	1,051,977	94,040	0	1,876,941	59,283	45,000	1,085,626	0	4,286	-99,375	0		-2,000,000
January 30, 2008	2,478,492	23,334	0	26,687	3,497,221	155,930	13,450	20,020	748,002	0	0	0		-2,006,152
March 10, 2008	5,790,753	83,960	0	93,815	5,448,023	77,046	214,495	263,393	1,579,017	0	31,004			-2,000,000
June 10, 2008	6,181,131	66,733	0	68,405	5,624,407	101,340	207,857	202,788	1,893,025		16,576			-2,000,000
September 15, 2008	5,816,459	208,746	0	106,030	4,527,084	136,660	110,052	283,951	2,373,039	0	75,158	-4,261		-2,000,000
October 28, 2008	661,939	20,704	0	25,777	1,883,813	32,294	46,715	58,851	563,554		7,847	22,384		-2,000,000
December 11, 2008	47,032,207	144,785	0	126,643	33,468,551	556,896	1,926,170	1,820,408	10,551,432		16,373	420,949		-2,000,000
December 28, 2008	52,584	10,888	0	79,101	1,066,945	42,974	56,560	6,378	755,270	0	1,708	32,760		-2,000,000

Total Storm Deferrals $171,530,371

# of Years = 7.66 $22,392,999 Average Annual "Incremental Deferred" Storm Cost

The cost detail for storms prior to February 2006 was obtained from the Attachment 11 filings. Attachment 11 grouped all charges from affiliates in a single line item that was classified in "Other" for the RAV-27 B response. This amount would have include base pay, bonus, overtime, etc...

Niagara Mohawk
Storms > $20,000,000 from 1990 to present
RAV-27 E_Attach 2

Event Date	Year	Deferral
January 1998	1998	67,724,598
October 12, 2006	2006	78,435,181
December 11, 2008	2008	47,389,800
Total Storm Deferrals > $20M		193,549,579

Note: The 1998 storm is net of FEMA recoveries that were in excess of $25 million.
Note: Costs shown are original costs and are not adjusted for inflation.

Major Storm Costs in Rate Years
Includes Incremental and Non-incremental Costs

Expense Type	Historic Test Year	Historic Test Year Adjustment	Adjusted Historic Test Year	Inflation Method	Rate Year 2011	Rate Year 2012	Rate Year 2013	Exhibit RRP-2, RRP-10 Schedule
Contractors	43,986,824	(44,585,419)	(598,595)	General	(617,837)	(628,959)	(640,909)	2
Employee Expenses	889,757		889,757	General	918,359	934,889	952,652	4
Hardware	1,373		1,373	General	1,417	1,442	1,470	5
Other	(43,218,533)	44,585,419	1,366,886	General	1,410,825	1,436,220	1,463,508	7
Service Co Operating Costs	18,876		18,876	General	19,482	19,833	20,210	17
Supervision & Admin	693		693	General	715	728	742	16
Sales Tax	139,162		139,162	General	143,636	146,221	148,999	18
Materials Outside Vendor	639,313		639,313	General	659,864	671,742	684,505	28
Materials From Inventory	1,519,938		1,519,938	General	1,568,797	1,597,036	1,627,379	29
Materials Stores Handling	247,625		247,625	General	255,585	260,186	265,130	30
Other Benefits	256,637		256,637	General	264,887	269,655	274,778	19-26
Transportation	1,958,573		1,958,573	General	2,021,533	2,057,920	2,097,021	32
Sub-total	6,440,237	-	6,440,237		6,647,263	6,766,914	6,895,485	
Base Labor	7,660,803		7,660,803	Labor	8,095,783	8,306,274	8,522,237	31
Overtime	14,007,756		14,007,756	Labor	14,803,117	15,187,998	15,582,886	31
Variable Pay	920,954		920,954	Labor	973,246	998,551	1,024,513	31
Payroll Tax	70,950		70,950	Labor	74,978	76,928	78,928	27
Sub-total	22,589,514		22,589,514		23,872,146	24,492,822	25,129,635	
Total	29,029,751		29,029,751		30,519,409	31,259,736	32,025,121	

Inflation Rates				
		29,900,643.20	31,312,913.95	31,373,952.77
General - (Exhibit RRP-7)				
Historic test year through 2011	3.2%	6,647,263.06	24,492,822.05	25,129,635.42
2012	1.8%	23,872,146.25	6,766,913.79	6,895,485.16
2013	1.9%	30,519,409.30	31,259,735.84	32,025,120.58

Labor - (Exhibit RRP-10, Workpaper 4 to RRP-2, sheet 10-12, 22-28)

2010	3.0%
2011-2013	2.60%

Note

Rate year major storm labor costs were calculated by escalating historic year costs with a composite rate (87% represented, 13% management) from wage and salary increases used in developing total labor costs presented in exhibit RRP-2, schedule 31. The 87% represented, 13% management split is the ratio of how historic year major storm base labor was charged.

Event	Total	Base Pay	Benefits	Bonus	Contractor	Emp Exp	Inventory	Other	Overtime	Sales & Use Tax	Transportation	Payroll Tax	Regional Disqual.	Storm Deduct
February 1, 2002 (55645)	932,000		514,857		4,383,021	474,195	300,854	-3,253,603	5,764,706	170,556	77,414			-7,500,000
March 9, 2002 (83110)	2,865,482		200,161		1,257,001	167,892	40,519	756,328	2,245,604	98,648	99,329			-2,000,000
April 4, 2003 (55823)	9,507,265		278,744		7,471,321	696,237	453,754	882,103	7,512,815	179,425	32,866			-8,000,000
Storm # 82950	576,960		140,024		643,056	100,412	6,075	111,057	1,571,541		4,795			-2,000,000
October 15, 2003 (82965)	1,231,941		184,359		750,453	137,265	8,816	54,790	2,069,124		27,134			-2,000,000
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February 17, 2006	2,835,937	211,301	0	0	4,697,117	269,290	403,418	725,285	5,574,853	212,131	-275,480	6,040	-988,018	-8,000,000
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October 28, 2006	219,340	1,249,177	82,105	1,680	2,936,696	57,606	20,584	55,585	20,215	35,961	683	0	-2,240,952	-2,000,000
December 1, 2006	2,117,778	1,051,977	94,040	0	1,876,941	59,283	45,000	1,085,626	0	4,286	-99,375	0		-2,000,000
January 30, 2008	2,478,492	23,334	0	26,687	3,497,221	155,930	13,450	20,020	748,002	0	0	0		-2,006,152
March 10, 2008	5,790,753	83,960	0	93,815	5,448,023	77,046	214,495	263,393	1,579,017	0	31,004			-2,000,000
June 10, 2008	6,181,131	66,733	0	68,405	5,624,407	101,340	207,857	202,788	1,893,025		16,576			-2,000,000
September 15, 2008	5,816,459	208,746	0	106,030	4,527,084	136,660	110,052	283,951	2,373,039	0	75,158	-4,261		-2,000,000
October 28, 2008	661,939	20,704	0	25,777	1,883,813	32,294	46,715	58,851	563,554		7,847	22,384		-2,000,000
December 11, 2008	47,032,207	144,785	0	126,643	33,468,551	556,896	1,926,170	1,820,408	10,551,432		16,373	420,949		-2,000,000
December 28, 2008	52,584	10,888	0	79,101	1,066,945	42,974	56,560	6,378	755,270	0	1,708	32,760		-2,000,000

Total Storm Deferrals $171,530,371

# of Years = 7.66 $22,392,999 Average Annual "Incremental Deferred" Storm Cost

The cost detail for storms prior to February 2006 was obtained from the Attachment 11 filings. Attachment 11 grouped all charges from affiliates in a single line item that was classified in "Other" for the RAV-27 B response. This amount would have include base pay, bonus, overtime, etc...

Niagara Mohawk
Storms > $20,000,000 from 1990 to present
RAV-27 E_Attach 2

Event Date	Year	Deferral
January 1998	1998	67,724,598
October 12, 2006	2006	78,435,181
December 11, 2008	2008	47,389,800
Total Storm Deferrals > $20M		193,549,579

Note: The 1998 storm is net of FEMA recoveries that were in excess of $25 million.
Note: Costs shown are original costs and are not adjusted for inflation.

Major Storm Costs in Rate Years
Includes Incremental and Non-incremental Costs

Expense Type	Historic Test Year	Historic Test Year Adjustment	Adjusted Historic Test Year	Inflation Method	Rate Year 2011	Rate Year 2012	Rate Year 2013	Exhibit RRP-2, RRP-10 Schedule
Contractors	43,986,824	(44,585,419)	(598,595)	General	(617,837)	(628,959)	(640,909)	2
Employee Expenses	889,757		889,757	General	918,359	934,889	952,652	4
Hardware	1,373		1,373	General	1,417	1,442	1,470	5
Other	(43,218,533)	44,585,419	1,366,886	General	1,410,825	1,436,220	1,463,508	7
Service Co Operating Costs	18,876		18,876	General	19,482	19,833	20,210	17
Supervision & Admin	693		693	General	715	728	742	16
Sales Tax	139,162		139,162	General	143,636	146,221	148,999	18
Materials Outside Vendor	639,313		639,313	General	659,864	671,742	684,505	28
Materials From Inventory	1,519,938		1,519,938	General	1,568,797	1,597,036	1,627,379	29
Materials Stores Handling	247,625		247,625	General	255,585	260,186	265,130	30
Other Benefits	256,637		256,637	General	264,887	269,655	274,778	19-26
Transportation	1,958,573		1,958,573	General	2,021,533	2,057,920	2,097,021	32
Sub-total	6,440,237	-	6,440,237		6,647,263	6,766,914	6,895,485	
Base Labor	7,660,803		7,660,803	Labor	8,095,783	8,306,274	8,522,237	31
Overtime	14,007,756		14,007,756	Labor	14,803,117	15,187,998	15,582,886	31
Variable Pay	920,954		920,954	Labor	973,246	998,551	1,024,513	31
Payroll Tax	70,950		70,950	Labor	74,978	76,928	78,928	27
Sub-total	22,589,514		22,589,514		23,872,146	24,492,822	25,129,635	
Total	29,029,751		29,029,751		30,519,409	31,259,736	32,025,121	

Inflation Rates		29,900,643.20	31,312,913.95	31,373,952.77
General - (Exhibit RRP-7)				
Historic test year through 2011	3.2%	6,647,263.06	24,492,822.05	25,129,635.42
2012	1.8%	23,872,146.25	6,766,913.79	6,895,485.16
2013	1.9%	30,519,409.30	31,259,735.84	32,025,120.58

Labor - (Exhibit RRP-10, Workpaper 4 to RRP-2, sheet 10-12, 22-28)

2010	3.0%
2011-2013	2.60%

Note

Rate year major storm labor costs were calculated by escalating historic year costs with a composite rate (87% represented, 13% management) from wage and salary increases used in developing total labor costs presented in exhibit RRP-2, schedule 31. The 87% represented, 13% management split is the ratio of how historic year major storm base labor was charged.

Date of Request: March 22, 2010
Due Date: April 1, 2010

Request No. AJR-1 SUPP
NMPC Req. No. NM 45 DPS 42

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Aric Rider

TO: Infrastructure and Operations Panel

Request:

In the plant model the Company has the following:

	6 mo Forecast	Per FY11 - FY15 Capex/COR Plan				
	Per FY10	FY11	FY12	FY13	FY14	FY15
Distribution						
Capex Forecast (Workpaper 3)	129.0	244.0	255.0	265.0	275.0	286.0
[redacted]						
COR Forecast	10.5	21.7	22.2	22.3	24.2	25.7
Sub-Transmission (TxD)						
Capex Forecast (Workpaper 4)	26.9	48.0	53.0	58.0	65.0	72.0
[redacted]						
COR Forecast	2.8	5.1	5.6	6.1	6.8	7.6
Transmission						
Capex Forecast (Workpaper 5)	73.0	132.0	228.0	290.0	295.0	295.0
[redacted]						
COR Forecast	4.6	10.0	17.3	22.0	22.4	22.4
Shared Services						
[redacted]						

How do you get from the COR %s listed in the file NY DIST COR MAT.xls - in response AJR-1 Attachment 5 - to the %s listed above. Where are the transmission and shared services %s developed?

Form 103

Response:

Distribution:
The COR percentages in the detail file (NY DIST COR MAT.xls, attached to the March 22, 2010 e-mail from Aric Rider to Glen DiConza) were developed using historical data and applied to a preliminary version of the 'project by project' budget based on the COR % listed by category. This provided a baseline as to the Cost of Removal percentage the Company could expect for FY11. The calculation produced a result of 8.9% for FY11. Then evaluating the investment outlined in the future years we determined that the COR % was realistic based on the historic COR %. The percentage was kept within a reasonable range for the forecasted projects for those years. See Attachment 1 (AJR-1 SUPP_Attach 1_COR FY11.xls) for a preliminary budget version for FY11 which shows the FY11 percentage using the COR % from AJR-1_Attach 5_NY DIST COR MAT.xls.

Transmission:
The Transmission COR percentages for FY11- FY15 were based on a three year historical average. The Company looked at the last three years (FY06/07-FY08/09) of COR based on prior years actual. We reviewed those percentages against future budgets and project mix to determine whether the percentages were reasonable. Following this determination, we reviewed whether the percentages assumed for future years were reasonable relative to the three year average percentages and future trends as well. The percentages were kept within a reasonable range for the projects in those years.

Shared Services:
Shared Services uses a historic average annual spend as the Cost of Removal estimate. This figure would be adjusted for any known large variances from past spend rates.

Name of Respondent:	Date of Reply:
Glen DiConza	4/1/2010
Antoinette Stores	4/1/2010

Form 103

Draft budget # - not final

271,000,000

23,886,155 COR Column Total

24,000,000 USED

8.9%

AJR-1 SUPP

Attachment 1

Proj #	BU	Project Description	[redacted]				BUDGET CLASS2	[redacted]	FY11 Removal
CNC022	36	Cent NY-Dist-3rd Party Attch Blankt	NY	NY	DIST	LINE & OTHER	3rd Party Attachments	[redacted]	14,250.00
CNE022	36	East NY-Dist-3rd Party Attch Blankt	NY	NY	DIST	LINE & OTHER	3rd Party Attachments	[redacted]	14,250.00
CNW022	36	West NY-Dist-3rd Party Attch Blankt	NY	NY	DIST	LINE & OTHER	3rd Party Attachments	[redacted]	11,250.00
C00194	36	NR-Distr-8043.08-CuNapth(soleowned)	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	9,600.00
C06723	36	Buffalo Station 29 Rebuild - Fdrs	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	156,000.00
C10164	36	Schuylerville 12- Reconductor Rt 29	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	32,000.00
C10960	36	IE - NE Cutout Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	16,000.00
C11099	36	IE-NE Cable Replacements Placeholde	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	459,840.00
C12967	36	IE - NC Cutout Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	16,000.00
C12968	36	IE - NW Cutout Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	16,000.00
C13282	36	IE-NW Cable Replacements Placeholde	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	619,680.00
C13822	36	IE-NC Cable Replacements Placeholde	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	430,720.00
C26902	36	Lape - Snyders Lake Tie	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	16,000.00
C26977	36	Doghouse Replacement - Central Div	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	20,000.00
C27864	36	Replace Open Wire Secondary-NY Eas	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	17,600.00
C27884	36	Replace open wire secondary-NY Cent	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	17,600.00
C27886	36	Replace open wire secondary-NY West	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	17,600.00
C27947	36	Buffalo Station 23 Rebuild - Fdrs	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	104,000.00
C27948	36	Buffalo Station 43 Rebuild - Fdrs	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	104,000.00
C27949	36	Buffalo Station 52 Rebuild - Fdrs	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	160,000.00
C28042	36	East NWP Relay Replacements	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	36,000.00
C28590	36	Gilbert Mills 51 Rebuild due to QRS	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	88,000.00
C28688	36	Brunswick 52 New feeder getaway	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	62,400.00
C28790	36	Alps - new dist sub - D Line work	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	168,000.00

C29113	36	Brook Road 36954 Getaway cable repl	NY	NY	DIST	LINE & OTHER	Asset Replacement	[redacted]	64,000.00
C29214	36	LV Neutral Cable Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		20,960.00
C31598	36	North Troy - Install Feeder Getaway	NY	NY	DIST	LINE & OTHER	Asset Replacement		57,600.00
C31633	36	208 Line Refurbishment	NY	NY	DIST	LINE & OTHER	Asset Replacement		1,600.00
C31860	36	IE - NE Replace open wire primary	NY	NY	DIST	LINE & OTHER	Asset Replacement		76,800.00
C31861	36	IE - NC Replace open wire primary	NY	NY	DIST	LINE & OTHER	Asset Replacement		63,200.00
C31862	36	IE - NW Replace open wire primary	NY	NY	DIST	LINE & OTHER	Asset Replacement		70,400.00
C32091	36	IE-NC Duct Replac Placeholder	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C32093	36	IE-NE_-Duct Replace Placeholder	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C32095	36	IE-NW_Duct replace Placeholder	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C32101	36	IE- NC- MH Program Placeholder	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C32102	36	IE-NW-MH Program Placeholder	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C32103	36	IE-NE-MH-Program-Placeholder	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C32292	36	Lowville-Boonville #22 Dist Underbu	NY	NY	DIST	LINE & OTHER	Asset Replacement		14,400.00
C32693	36	V-72 Howard St Replace Vault Roof	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33173	36	Albany Network Equipment	NY	NY	DIST	LINE & OTHER	Asset Replacement		240,000.00
C33476	36	Buffalo Station 27 Rebuild - Line	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C33477	36	Buffalo Station 37 Rebuild - Line	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C33478	36	Buffalo Station 59 Rebuild - Line	NY	NY	DIST	LINE & OTHER	Asset Replacement		16,000.00
C33908	36	V2325 Albany NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33909	36	V2326 Albany NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33910	36	V2327 Albany NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33911	36	V-6 Albany NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33912	36	V5825 Schenectady NY Roof Repl	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33913	36	V573 Troy NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33914	36	V-500 Troy NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
C33915	36	V-198 Albany NY Roof Replacement	NY	NY	DIST	LINE & OTHER	Asset Replacement		24,000.00
CNC017	36	Cent NY-Dist-Asset Replace Blanket	NY	NY	DIST	LINE & OTHER	Asset Replacement		363,360.00
CNE017	36	East NY-Dist-Asset Replace Blanket	NY	NY	DIST	LINE & OTHER	Asset Replacement		165,120.00
CNW017	36	West NY-Dist-Asset Replace Blanket	NY	NY	DIST	LINE & OTHER	Asset Replacement		412,960.00
C06722	36	Buffalo Indoor Sub. #29 Refurb.	NY	NY	DIST	SUB	Asset Replacement		29,000.00
C08435	36	White Lake Station Upgrades	NY	NY	DIST	SUB	Asset Replacement		16,000.00

C18850	36	Circuit Switcher Strategy Co:36 DxT	NY	NY	DIST	SUB	Asset Replacement	[redacted]	18,000.00
C24240	36	Battery Strategy FY09 CO36 DxT	NY	NY	DIST	SUB	Asset Replacement	[redacted]	2,500.00
C25639	36	Buffalo Indoor Sub. #23 Refurb.	NY	NY	DIST	SUB	Asset Replacement	[redacted]	13,000.00
C25659	36	Buffalo Indoor Sub. #52 Refurb.	NY	NY	DIST	SUB	Asset Replacement	[redacted]	21,200.00
C25660	36	Buffalo Indoor Sub. #43 Refurb.	NY	NY	DIST	SUB	Asset Replacement	[redacted]	19,000.00
C25801	36	IE - NY ARP Transformers	NY	NY	DIST	SUB	Asset Replacement	[redacted]	30,000.00
C26054	36	NY ARP MetalClad Equipment	NY	NY	DIST	SUB	Asset Replacement	[redacted]	5,000.00
C26760	36	NY Small Capital Items	NY	NY	DIST	SUB	Asset Replacement	[redacted]	2,000.00
C28788	36	Alps - new dist sub - add feeder	NY	NY	DIST	SUB	Asset Replacement	[redacted]	2,000.00
C29205	36	Network Transformer Replacement	NY	NY	DIST	SUB	Asset Replacement	[redacted]	6,000.00
C29206	36	Network Protector Replacement	NY	NY	DIST	SUB	Asset Replacement	[redacted]	6,000.00
C32004	36	Mobile Readiness-NY Central	NY	NY	DIST	SUB	Asset Replacement	[redacted]	4,000.00
C32005	36	Mobile Readiness-NY West	NY	NY	DIST	SUB	Asset Replacement	[redacted]	12,000.00
C32014	36	Batts/Charg- NY West	NY	NY	DIST	SUB	Asset Replacement	[redacted]	7,000.00
C32252	36	NE ARP Breakers & Reclosers	NY	NY	DIST	SUB	Asset Replacement	[redacted]	14,200.00
C32253	36	NC ARP Breakers & Reclosers	NY	NY	DIST	SUB	Asset Replacement	[redacted]	19,400.00
C32261	36	NW ARP Breakers & Reclosers	NY	NY	DIST	SUB	Asset Replacement	[redacted]	12,600.00
C32296	36	Altamont Sub Metalclad Replacement	NY	NY	DIST	SUB	Asset Replacement	[redacted]	17,000.00
C32298	36	Market Hill Sub Metalclad Replacemt	NY	NY	DIST	SUB	Asset Replacement	[redacted]	3,000.00
C32340	36	Ellicott Regulator Replacement	NY	NY	DIST	SUB	Asset Replacement	[redacted]	9,000.00
C33473	36	Buffalo Station 27 Rebuild - Sta	NY	NY	DIST	SUB	Asset Replacement	[redacted]	6,000.00
C33474	36	Buffalo Station 37 Rebuild - Sub	NY	NY	DIST	SUB	Asset Replacement	[redacted]	6,000.00
C33475	36	Buffalo Station 59 Rebuild - Sub	NY	NY	DIST	SUB	Asset Replacement	[redacted]	6,000.00
C26159	36	FH - NE D-Line Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	[redacted]	635,900.00
C26160	36	FH - NC D-Line Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	[redacted]	635,900.00
C26161	36	FH - NW D-Line Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	[redacted]	635,900.00
C26162	36	FH - NE UG Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	[redacted]	83,300.00
C26163	36	NC - UG Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	[redacted]	83,300.00
C26164	36	NW - UG Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	[redacted]	83,400.00
CNC014	36	Cent NY-Dist-Damage/Failure Blanket	NY	NY	DIST	LINE & OTHER	Damage/Failure	[redacted]	676,600.00
CNE014	36	East NY-Dist-Damage/Failure Blanket	NY	NY	DIST	LINE & OTHER	Damage/Failure	[redacted]	925,820.00
CNW014	36	West NY-Dist-Damage/Failure Blanket	NY	NY	DIST	LINE & OTHER	Damage/Failure	[redacted]	854,590.00

RESERVE (	**36**	**Reserve for Damage/Failure Unidentifie**	NY	NY	DIST	LINE & OTHER	Damage/Failure	[redacted]	436,900.00
C18595	36	DxT Substation Dmg/Fail Reserve C36	NY	NY	DIST	SUB	Damage/Failure	[redacted]	2,000.00
CNC002	36	Cent NY-Dist-Subs Blanket	NY	NY	DIST	SUB	Damage/Failure	[redacted]	7,340.00
CNE002	36	East NY-Dist-Subs Blanket	NY	NY	DIST	SUB	Damage/Failure	[redacted]	12,560.00
CNW002	36	West NY-Dist-Subs Blanket	NY	NY	DIST	SUB	Damage/Failure	[redacted]	7,340.00
RESERVE (	**36**	**Reserve for Damage/Failure Unidentifie**	NY	NY	DIST	SUB	Damage/Failure	[redacted]	20,000.00
CNC070	36	Cent NY-General-Genl Equip Blanket	NY	NY	DIST	LINE & OTHER	General Equipment - Dist	[redacted]	-
CNE070	36	East NY-Genl Equip Budgetary Reserv	NY	NY	DIST	LINE & OTHER	General Equipment - Dist	[redacted]	-
CNW070	36	West NY-General-Genl Equip Blanket	NY	NY	DIST	LINE & OTHER	General Equipment - Dist	[redacted]	-
RESERVE (	**36**	**Reserve for General Equipment Specifi**	NY	NY	DIST	LINE & OTHER	General Equipment - Dist	[redacted]	-
CNC009	36	Cent NY-Dist-Land/Rights Blanket	NY	NY	DIST	LINE & OTHER	Land and Land Rights - Dist	[redacted]	13,250.00
CNW009	36	West NY-Dist-Land/Rights Blanket	NY	NY	DIST	LINE & OTHER	Land and Land Rights - Dist	[redacted]	5,950.00
C00376	36	St. Johnsville 51-Wagner/Wiltse Rds	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	21,000.00
C06765	36	East Golah -F5151E, F5151W & F5151	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	82,530.00
C10967	36	IE - NW Dist Transformer Upgrades	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	80,535.00
C12719	36	Rosa Road 55 - Overloaded Ratio bks	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	5,250.00
C14846	36	IE - NC Dist Transformer Upgrades	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	80,535.00
C15828	36	IE - NE Dist Transformer Upgrades	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	80,535.00
C18991	36	Port Henry 51 - Convert Westport	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	36,750.00
C26379	36	Attica12-Rebuild,Xfer F1263 to 0158	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	84,000.00
C28022	36	Sycaway-add new feeders	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	28,350.00
C28023	36	Reynolds Rd - add new feeders	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	66,150.00
C28545	36	LeMoyne Ave Rebild	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	42,000.00
C28607	36	Lehigh 66952 Tie With Colosse 32151	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	79,800.00
C28608	36	McGraw 69 Low Voltage improvement	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	47,250.00
C28618	36	Valley 59476 Rebuild Rasbach Rd	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	4,200.00
C28622	36	Poland Convert Old State Rd	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	36,855.00
C28765	36	Johnson 35251 - getaway replacement	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	9,450.00
C28772	36	Inman Rd - add new feeders	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	105,000.00
C28780	36	Seminole 33904 - add feeder tie	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	10,500.00
C28781	36	Riverside 28854 - replace getaway	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	16,275.00
C28816	36	Chittenango Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	31,500.00

C28820	36	Park Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	13,020.00
C28825	36	Krumkill Voorheesville Tie	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	52,500.00
C28832	36	Bartell 56 Orangeport	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	26,250.00
C28837	36	Canajoharie D-Line Work	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	94,500.00
C28843	36	Church St 04358 exten.	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	14,805.00
C28844	36	Brook Rd 36957 Exten. Adams Road	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	49,665.00
C28847	36	Fairdale Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	31,500.00
C28848	36	Mexico Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	21,000.00
C28849	36	Phoenix Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	21,000.00
C28852	36	Starr 53 Step Down	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	52,500.00
C28854	36	Cortland 02 Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	10,500.00
C28869	36	E Syracsue 69 Conductor	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	6,300.00
C28870	36	Station 21 - Split F2173	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	26,250.00
C28929	36	Frankhauser New Station - Line Work	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	63,000.00
C29030	36	Batavia 01 - UG Cable Recond.	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	105,000.00
C29181	36	Station 79 - F7961 Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	15,382.50
C29182	36	Station 79 - F7962 Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	19,950.00
C30506	36	N Syracuse Sub Getaways	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	3,150.00
C32171	36	Amsterdam 32654 - extension	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	42,000.00
C32345	36	Butts Rd. 7252 Extension	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	70,875.00
C32350	36	Albion 8064 Getaway Reconductoring	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	19,687.50
C32390	36	NW-Batavia Sub Dist. Line Cap Banks	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	13,860.00
C32413	36	Tonawanda 4.16 057 Recon UG Getaw	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	35,122.50
C32452	36	NW 15564 Fdr, Recond ug getaway	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	11,812.50
C32453	36	NW Fdr 4671 Recond UG cable	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	19,687.50
C32470	36	NW F3964 Extend ug, Xfer load	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	18,900.00
C32494	36	Gilbert Mill Relief	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	53,392.50
C32510	36	Brockport Feeder Capacitors	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	26,460.00
C32595	36	Rathbun Labrador conversion	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	15,750.00
C32598	36	Ogden Brook - Install new feeders	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	10,500.00
CNC016	36	Cent NY-Dist-Load Relief Blanket	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	43,575.00
CNE016	36	East NY-Dist-Load Relief Blanket	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	21,735.00

CNW016	36	West NY-Dist-Load Relief Blanket	NY	NY	DIST	LINE & OTHER	Load Relief	[redacted]	50,610.00
C06533	36	East Golah 51 - Second Bank	NY	NY	DIST	SUB	Load Relief	[redacted]	13,790.00
C08153	36	PS&I Activity - New York	NY	NY	DIST	SUB	Load Relief	[redacted]	1,000.00
C15669	36	Cuba 05 - Replace Transformer Bank	NY	NY	DIST	SUB	Load Relief	[redacted]	250.00
C15678	36	Chautauqua 57 - Replace Xfmr	NY	NY	DIST	SUB	Load Relief	[redacted]	8,550.00
C15765	36	Sheppard Rd. 29 - Second Bank	NY	NY	DIST	SUB	Load Relief	[redacted]	7,500.00
C26418	36	Sycaway - Add M/C and 13.2kV Bus	NY	NY	DIST	SUB	Load Relief	[redacted]	20,660.00
C26481	36	S. Newfane 71 - Replace Bank	NY	NY	DIST	SUB	Load Relief	[redacted]	250.00
C26577	36	Buffalo Sta. 63 bank replacement	NY	NY	DIST	SUB	Load Relief	[redacted]	4,600.00
C26819	36	Sycaway add 2nd Xfmr & 115 kV equip	NY	NY	DIST	SUB	Load Relief	[redacted]	19,290.00
C27062	36	East Golah 51 - Secondary Breakers	NY	NY	DIST	SUB	Load Relief	[redacted]	7,000.00
C27322	36	Raquette Lake 2.5 MVA	NY	NY	DIST	SUB	Load Relief	[redacted]	1,000.00
C27323	36	NR- Morristown 2.5 MVA	NY	NY	DIST	SUB	Load Relief	[redacted]	1,420.00
C27449	36	Swann Rd TB2 Replacement	NY	NY	DIST	SUB	Load Relief	[redacted]	22,000.00
C28770	36	Inman Rd -Add M/C & 13.2kV Bus work	NY	NY	DIST	SUB	Load Relief	[redacted]	10,000.00
C28831	36	N Syracuse Capacity Inc	NY	NY	DIST	SUB	Load Relief	[redacted]	6,700.00
C28931	36	Frankhauser-115-13.2KV- Bus & Bkrs	NY	NY	DIST	SUB	Load Relief	[redacted]	3,000.00
C29049	36	Younsgtown 88 - Station Rebuild	NY	NY	DIST	SUB	Load Relief	[redacted]	7,500.00
C29186	36	Station 214 - Install TB2	NY	NY	DIST	SUB	Load Relief	[redacted]	2,000.00
C29187	36	Station 214 - New F21466	NY	NY	DIST	SUB	Load Relief	[redacted]	1,000.00
C31550	36	DxT Study Budgetary Reserve - NIMO	NY	NY	DIST	SUB	Load Relief	[redacted]	1,000.00
C32339	36	Farmersville Transformer Replacemen	NY	NY	DIST	SUB	Load Relief	[redacted]	5,250.00
C32342	36	Sinclairville Transformer Replace	NY	NY	DIST	SUB	Load Relief	[redacted]	5,250.00
C32346	36	W. Albion Transformer Addition	NY	NY	DIST	SUB	Load Relief	[redacted]	5,000.00
C32354	36	NW Baker St Station Cap Bank	NY	NY	DIST	SUB	Load Relief	[redacted]	1,500.00
C32367	36	Bennett Rd. Sub Capacitor Install	NY	NY	DIST	SUB	Load Relief	[redacted]	8,760.00
C32594	36	Labrador 115-13.2kV	NY	NY	DIST	SUB	Load Relief	[redacted]	7,500.00
C32597	36	Ogden Brook- install 13.2 kV s/gear	NY	NY	DIST	SUB	Load Relief	[redacted]	2,500.00
C00056	36	Storm Damage - Dist - Western Div	NY	NY	DIST	LINE & OTHER	Major Storms - Dist	[redacted]	48,300.00
C00328	36	Storm Damage Distribution East Div.	NY	NY	DIST	LINE & OTHER	Major Storms - Dist	[redacted]	48,300.00
C12965	36	Storm Damage-Dist-Cent Div	NY	NY	DIST	LINE & OTHER	Major Storms - Dist	[redacted]	48,300.00
CN3604	36	NiMo Meter Purchases	NY	NY	DIST	LINE & OTHER	Meters - Dist	[redacted]	-

CNC004	36	Cent NY-Dist-Meter Blanket	NY	NY	DIST	LINE & OTHER	Meters - Dist	[redacted]	201,000.00
CNE004	36	East NY-Dist-Meter Blanket	NY	NY	DIST	LINE & OTHER	Meters - Dist	[redacted]	228,900.00
CNW004	36	West NY-Dist-Meter Blanket	NY	NY	DIST	LINE & OTHER	Meters - Dist	[redacted]	215,100.00
C24233	36	Primary service for Taconic Farms	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	30,000.00
C29682	36	GML Tower	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	27,300.00
C30685	36	Wal-Mart Sheridan Dr. - New Service	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	20,760.00
CNC011	36	Cent NY-Dist-New Bus-Comm Blanket	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	244,140.00
CNE011	36	East NY-Dist-New Bus-Comm Blanket	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	237,900.00
CNW011	36	West NY-Dist-New Bus-Comm Blanket	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	269,160.00
RESERVE (	**36**	**Reserve for New Business Commercial**	NY	NY	DIST	LINE & OTHER	New Business - Commercial	[redacted]	59,940.00
C31298	36	Fairland URD	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	15,200.00
C31602	36	Bolton 52 - Convert Valley Woods Rd	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	25,000.00
C31612	36	Helderberg Meadows URD, Phase 1	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	36,000.00
C32301	36	Bell's Pond Mobile Home URD	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	10,000.00
C32891	36	Jenna's Forest URD	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	12,000.00
CNC010	36	Cent NY-Dist-New Bus-Resid Blanket	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	1,028,600.00
CNE010	36	East NY-Dist-New Bus-Resid Blanket	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	977,200.00
CNW010	36	West NY-Dist-New Bus-Resid Blanket	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	771,500.00
RESERVE (	**36**	**Reserve for New Business Residential (**	NY	NY	DIST	LINE & OTHER	New Business - Residential	[redacted]	240,800.00
C26839	36	Mercury Vapor Replacement	NY	NY	DIST	LINE & OTHER	Outdoor Lighting - Capital	[redacted]	575,000.00
CNC012	36	Cent NY-Dist-St Light Blanket	NY	NY	DIST	LINE & OTHER	Outdoor Lighting - Capital	[redacted]	335,225.00
CNE012	36	East NY-Dist-St Light Blanket	NY	NY	DIST	LINE & OTHER	Outdoor Lighting - Capital	[redacted]	215,510.00
CNW012	36	West NY-Dist-St Light Blanket	NY	NY	DIST	LINE & OTHER	Outdoor Lighting - Capital	[redacted]	389,045.00
C15724	36	NYSDOT Ridge Rd Bridge	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	13,600.00
C21511	36	DOT Queensbury Exit 18	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	256,000.00
C22173	36	NYS DOT Route 5	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	120,000.00
C22454	36	Green Ave Road Widening	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	12,000.00
C26639	36	Seneca Niagara Casino Relocation NF	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	8,000.00
C29742	36	DOTR I-81 bridge reconstruction Syr	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	2,720.00
C29825	36	DOT Albany Co., Johnston Rd.	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	16,000.00
C30825	36	372 Battenkill Bridge - DOT	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	20,000.00
C31258	36	DOT Glenville, Glenridge Rd.	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	54,400.00

C31318	36	DOT Albany, Fuller Rd.	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	16,000.00
C31543	36	DOT Amsterdam, Bridge St.	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	51,200.00
C31554	36	DOT PIN3045.55 Rt104 Osw-Scriba	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	32,000.00
C31811	36	DOT Erie Canal Lock E-13	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	86,400.00
C31868	36	DOTR PIN7804.42 Rt68	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	24,000.00
C32234	36	DOTR Latham, Rte.'s 2/7 Br/I-87	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	35,200.00
C32286	36	DOT Saratoga, Rte. 9P Bridge	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	32,000.00
C32359	36	NYSDOTR Rte. 28, Woodgate to McKe	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	24,000.00
C32432	36	DOT Schoharie, Rte.'s 30, 30A & 443	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	25,600.00
C32850	36	DOT 4098.04- Rt 98 & 238 Attica	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	27,840.00
C33253	36	DOT-Relocate facilities Maple Rd	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	1,920.00
C33351	36	DOT CR106/Pine Grove Rd	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	7,040.00
CNC013	36	Cent NY-Dist-Public Require Blanket	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	167,520.00
CNE013	36	East NY-Dist-Public Require Blanket	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	301,600.00
CNW013	36	West NY-Dist-Public Require Blanket	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	226,240.00
RESERVE (	**36**	**Reserve for Public Requirements Unide**	NY	NY	DIST	LINE & OTHER	Public Requirements	[redacted]	254,080.00
C06679	36	Boyntonville 51 Regulators	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	4,500.00
C06698	36	Clinton 53 - Convert Ft Plain	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	20,700.00
C06850	36	Whitaker 51 River Crossing	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	6,750.00
C07438	36	Chestertown 52 - Duell Hill Rd.	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	13,500.00
C07477	36	Northville 52 - Convert N. Shore Rd	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	9,000.00
C07482	36	Battenkill 34257 - Rebuild/convert	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	11,250.00
C07798	36	EJ West 03841 - Convert to 13.2kV	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	9,000.00
C08606	36	Delmar 440, Jun, Vooh 52 Conversion	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	90,000.00
C13266	36	IE - NE Recloser Installations	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	148,500.00
C13267	36	IE - NC Recloser Installations	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	148,500.00
C13268	36	IE - NW Recloser Installations	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	153,000.00
C15727	36	NR-Gilpin Bay 95661-Fish Creek Pond	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	11,250.00
C15732	36	NR-Gilpin Bay 95661-Hoel Pond	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	10,890.00
C16117	36	IE - NE ERR and Fuse	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	36,000.00
C16118	36	IE - NC ERR and Fuse	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	36,000.00
C16119	36	IE - NW ERR and Fuse	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	36,000.00

C17962	36	Schroon 51 - Rebuild Route 74	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	13,500.00
C19272	36	Caroga - G'ville 53 Feeder Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	15,750.00
C20691	36	Selkirk - Bethlehem Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	3,600.00
C22959	36	NR-W.Adams87554-Church St	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	9,000.00
C26876	36	Corinth 52 - Eastern Ave. Rebuild	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	81,000.00
C26877	36	Guy Park Retirement Dist. Line	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	4,500.00
C26973	36	NR-State St 95463-Judson St Rebuild	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	14,400.00
C28176	36	Scofield 53 - Hadley/Harrisburg Rds	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	22,050.00
C28606	36	F5769/5763 Rebuild r/o Floradale	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	22,500.00
C28610	36	Peterboro Reconductor Main St.	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	18,000.00
C28616	36	Walesville Reconductor Utica St	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	9,000.00
C28617	36	Lehigh 66954 Teelin Rd Relocate	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	9,000.00
C28619	36	Cavanaugh 61652 River Road	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	10,980.00
C28620	36	Oneida 50153 Route 5	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	22,680.00
C28623	36	Poland 62257 Steuben Rd	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	6,300.00
C28625	36	F20871 rebuild ties F4768/F2569	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	14,580.00
C28652	36	Delameter F9352 new ties w/18251,53	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	27,000.00
C28689	36	F9753 Rebuild/Conv tie w/F21754	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	17,100.00
C28692	36	F8566 Rebuild Various Sections	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	9,000.00
C28716	36	Knapp Rd 22651 Feeder Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	50,580.00
C28717	36	N.Leroy 0455 - Mumford 5052 Fdr Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	36,000.00
C28718	36	E.Batavia 2855 - N.Leroy 0456 Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	68,580.00
C28719	36	Batavia 0155 - Knapp Rd 22651 Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	47,880.00
C28720	36	N.Eden 8251 Tie w/ F8861 & F8862	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	3,600.00
C28721	36	Delameter 9354 - 9353 Feeder Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	16,740.00
C28723	36	Delameter 9352 - Eden Ctr 8862 Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	20,880.00
C28726	36	Sweet Home F22457 tie with F2165	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	5,400.00
C28791	36	Krumkill 51 Russell Rd convert	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	6,075.00
C28814	36	Arbor Hill URD - Riverside 28858	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	13,500.00
C28823	36	Pinebush 37154 Prescott Woods	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	27,000.00
C28826	36	Stonehenge URD	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	16,200.00
C29101	36	NR-N Gouverneur 98352-Rt58 Transfer	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	27,000.00

C29424	36	Battenkill 56 - Weibel 51 Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	6,300.00
C29425	36	Brook Road 55/57 - Daniels Rd	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	16,200.00
C29426	36	Center St 54 - Rebuild Route 5S	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	63,000.00
C29429	36	Chestertown 52 - Schroon River Rd	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	45,000.00
C29430	36	Corinth 52 - Hudson River Crossing	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	18,000.00
C29431	36	Farnan Rd 51 - Bluebird Road	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	72,000.00
C29433	36	Inghams 51 - Route 108	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	18,000.00
C29434	36	Middleburg 51 - Tie to Schoharie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	10,800.00
C29435	36	Northville 52 - EJ West 51 Tie	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	63,000.00
C29438	36	Scofield Rd 53 - Tie to Corinth 51	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	72,000.00
C31772	36	Lehigh 66951 tie with Turin 65355	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	45,000.00
C32576	36	Pockets of Poor Performance - NYW	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	63,900.00
C32577	36	Pockets of Poor Performance - NYC	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	63,900.00
C32578	36	Pockets of Poor Performance - NYE	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	63,900.00
CNC015	36	Cent NY-Dist-Reliability Blanket	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	156,510.00
CNE015	36	East NY-Dist-Reliability Blanket	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	146,790.00
CNW015	36	West NY-Dist-Reliability Blanket	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	293,490.00
RESERVE	36	Reserve for Reliability Unidentified Spe	NY	NY	DIST	LINE & OTHER	Reliability - Dist	[redacted]	14,895.00
C19851	36	REP - Dist Subs Without RTUs	NY	NY	DIST	SUB	Reliability - Dist	[redacted]	-
C20173	36	REP - Dist Subs EMS RTU DNP Plan	NY	NY	DIST	SUB	Reliability - Dist	[redacted]	3,000.00
C22151	36	NY RTU Program - DxT Subs	NY	NY	DIST	SUB	Reliability - Dist	[redacted]	36,000.00
C28449	36	Metallic Pilot Wire Protection Repl	NY	NY	DIST	SUB	Reliability - Dist	[redacted]	-
C10968	36	FH - NW Feeder Hardening	NY	NY	DIST	LINE & OTHER	Reliability - FEEDER HARDENING	[redacted]	316,200.00
C13145	36	FH - NC Feeder Hardening	NY	NY	DIST	LINE & OTHER	Reliability - FEEDER HARDENING	[redacted]	316,200.00
C13146	36	FH - NE Feeder Hardening	NY	NY	DIST	LINE & OTHER	Reliability - FEEDER HARDENING	[redacted]	316,200.00
C04157	36	Telecom and Radio Equipment	NY	NY	DIST	LINE & OTHER	Telecommunications Capital - Dist	[redacted]	-
CNC021	36	Cent NY-Dist-Telecomm Blanket	NY	NY	DIST	LINE & OTHER	Telecommunications Capital - Dist	[redacted]	-
CNE021	36	East NY-Dist-Telecomm Blanket	NY	NY	DIST	LINE & OTHER	Telecommunications Capital - Dist	[redacted]	-
CNW021	36	West NY-Dist-Telecomm Blanket	NY	NY	DIST	LINE & OTHER	Telecommunications Capital - Dist	[redacted]	-
CN3620	36	NiMo Transformer Purchases	NY	NY	DIST	LINE & OTHER	Transformers & Related Equipment	[redacted]	-
CNC020	36	Cent NY-Dist-Transf/Capac Blanket	NY	NY	DIST	LINE & OTHER	Transformers & Related Equipment	[redacted]	-
CNE020	36	East NY-Dist-Transf/Capac Blanket	NY	NY	DIST	LINE & OTHER	Transformers & Related Equipment	[redacted]	-

CNW020	36	West NY-Dist-Transf/Capac Blanket	NY	NY	DIST	LINE & OTHER	Transformers & Related Equipment	[redacted]	-

[redacted]

Date of Request: April 23, 2010
Due Date: May 3, 2010

Request No. AJR-1 SUPP 2
NMPC Req. No. NM 45 DPS 42

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Aric Rider

TO: Infrastructure and Operations Panel

Request:

The response looks like I now have a link between the distribution COR and the plant model. However, I don't seem to see the development of the sub-t, transmission, or shared services COR percentages. Am I missing something?

Response:

The attached spreadsheets are used in Cost of Removal (COR) estimation for:

1) Sub-Transmission: AJR-1 SUPP 2_SubTransmision Cost of Removal Percentage Calc.xls
2) Transmission: AJR-1 SUPP 2_Transmission Cost of Removal Percentage Calc.xls
3) Shared Services: AJR-1 SUPP 2_Shared Services Cost of Removal Budget Estimate.xls

Sub-transmission and transmission apply a historic estimated percentage to the budgeted capital funds for the estimated COR while Shared Services uses a flat dollar estimate consistent with prior years cost of removal totals.

Name of Respondent:
Glen DiConza

Date of Reply:
April 29, 2010

Form 103

Tranmission Cost of Removal

Sum of Amount		
FY	Funding Type	Total
2007	P_Common Plant - Capital	15,240
	P_Electric Distribution Line	(1,261,204)
	P_Electric Distribution Sub	144,218
	P_Electric General Plant	594,133
	P_Electric Transmission Line	1,836,241
	P_Electric Transmission Sub	1,264,311
	P_Gas Distribution - Capital	1,065
	P_Gas Station - Distribution	577
	z_Cap Allox-Dist **PPlantUseONLY	1,270,181
2007 Total		**3,864,762**
2008	P_Common Plant - Capital	1,380
	P_Electric Distribution Line	441,111
	P_Electric Distribution Sub	96,994
	P_Electric General Plant	(212,650)
	P_Electric Transmission Line	3,798,494
	P_Electric Transmission Sub	855,793
	P_Gas Distribution - Capital	1,223
	z_Cap Allox-Dist **PPlantUseONLY	(1,803)
2008 Total		**4,980,541**
2009	P_Dist by Transmission Substation	31,561
	P_Electric Distribution Line	26,060
	P_Electric Distribution Sub	68,502
	P_Electric GenPlant Fac IT Shared	157,082
	P_Electric Transmission Line	3,916,294
	P_Electric Transmission Sub	932,300
	z_Cap Allox-Dist **PPlantUseONLY	1,650
	#N/A	169
2009 Total		**5,133,616**
Grand Total		**13,978,918**

2007	**COR**	**Total Spend**	**%**
TxT	3,864,762	50,900,000	7.6%
	3,864,762	**50,900,000**	**7.6%**

2008	**COR**	**Total Spend**	**%**
TxT	4,980,541	62,800,000	7.9%
	4,980,541	**62,800,000**	**7.9%**

2009	**COR**	**Total Spend**	**%**
TxT	5,133,616	69,425,248	7.4%
	5,133,616	**69,425,248**	**7.4%**

Average	
TxT	7.6%

Common/General Plant Actuals
by Fiscal Year - Cost of Removal

	Distribution Actuals
FY 2008	1.7
FY 2009	0.8
FY 2010	2.3
	1.6 **Historic annual average COR per year**

Use for Plan **$** **1.5** **per fiscal year**

(approx. rounded historic annual average)

COST OF REMOVAL AS A PERCENTAGE OF CAPITAL SPEND
SUB-TRANSMISSION PROJECTS
Moving Annual Total (MAT) Analysis

Sum of CR Act $	Fiscal Yr	Period										
	2008											
CHARGE	1	2	3	4	5	6	7	8	9	10	11	12
Capital	1,321,385	1,969,784	2,040,341	2,254,018	2,126,828	2,007,450	32,537	3,521,060	2,466,330	2,683,411	3,136,527	3,138,334
COR	185,636	605,135	308,675	218,665	308,522	424,716	213,101	548,550	393,905	371,897	324,651	338,969
Grand Total	1,507,020	2,574,919	2,349,016	2,472,683	2,435,349	2,432,166	245,637	4,069,610	2,860,235	3,055,308	3,461,179	3,477,303

	MAT %											
COR	15.9%	15.4%	13.9%	13.3%	13.0%	13.3%	12.0%	10.7%	10.2%	10.0%	9.5%	9.8%
	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008	Jan-2009	Feb-2009

	MAT at....
10.0%	**12/31/2008**
10.6%	**3/31/2009**
12.2%	**6/30/2009**
10.9%	**Average**
10.5%-10.6%	**USED**

Used approximate average of the cost of removal Moving Annual Total (MAT) for Sub-transmission at different end of quarter points...

2009											
1	2	3	4	5	6	7	8	9	10	11	12
1,359,451	4,745,175	3,342,540	3,177,054	2,454,334	3,125,628	2,703,077	1,762,178	1,589,477	2,109,703	2,073,038	3,013,478
69,965	576,795	315,071	234,628	466,697	137,973	50,651	194,115	237,712	166,713	316,274	571,709
1,429,416	5,321,971	3,657,610	3,411,682	2,921,031	3,263,601	2,753,728	1,956,293	1,827,189	2,276,416	2,389,312	3,585,187

10.6%	10.6%	11.5%	12.2%	12.4%	12.4%
Mar-2009	Apr-2009	May-2009	Jun-2009	Jul-2009	Aug-2009

2010							Grand Total
1	2	3	4	5	6	7	
2,167,321	236,440	2,284,151	4,336,349	1,846,948	2,672,924	123,988	71,821,256
155,513	346,913	383,262	428,043	378,757	470,522	(5,723)	9,738,013
2,322,834	583,353	2,667,414	4,764,392	2,225,705	3,143,446	118,265	81,559,270

Date of Request: February 17, 2010
Due Date: March 1, 2010

Request No. CVB-4
NMPC Req. No. NM 51 DPS 48

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christian Bonvin

TO: Infrastructure and Operations Panel

Request:

1. Please summarize the Distribution tree-trimming program used during the test year -- including the voltage classes covered by the program -- and indicate any changes that have been made to the program since 2002.
2. Please describe the proposed Distribution tree-trimming program for 2011 through 2013.
3. Please describe differences between National Grid's Enhance Hazard Tree Mitigation (EHTM) program and its previous Total Outage Reduction Operation (TORO) program with respect to tree removal.
4. Please provide any workpapers supporting how the Company forecasted its overall Distribution tree-trimming expenses.
5. Please provide an Excel file with the following information on a company-wide basis and for each division (East, Central, West) for the years 2002 through 2009:
    A. Actual spending and budget for all tree trimming activities;
    B. Actual spending and budget for cycle tree trimming;
    C. Number of miles trimmed per year cycle trimming;
    D. Average cost per mile;
    E. Actual spending and budget for hazard tree removal;
    F. Total number of hazard trees removed per year;
    G. Average cost for removal of danger tree;
    H. Actual spending and budget for "hot spot" trimming.
6. Please provide an Excel file with the following information on a company-wide basis and for each division (East, Central, West) for the years 2011 through 2013:
    A. Forecasted budget for all tree trimming activities;
    B. Forecasted budget for cycle tree trimming;
    C. Number of miles planned to be trimmed per year;
    D. Forecasted average costs per mile;
    E. Forecasted budget for hazard tree removal;

F. Total number of hazard trees expected removed per year;
G. Forecasted average cost for removal of danger tree;
H. Forecasted budget for "hot spot" trimming.

Response:

1. Please refer to Attachment 1 (CVB-4_Attach 1_*Vegetation Management Strategy – June 2008)* for a full description of the distribution vegetation management program used during the test year. In summary, the Company implements two reliability based vegetation management strategies. These are cycle based circuit pruning and enhanced hazard tree mitigation "EHTM". The main purpose of these programs is to create and maintain clearance between energized distribution conductors and vegetation, primarily tree limbs. In addition, the hazard tree program is intended to minimize the frequency and damaging effects of large tree and large limb failures from along side and above the Company's overhead primary distribution assets. This is a reliability-focused strategy designed to meet state regulatory targets. In addition, the circuit pruning program provides a measure of public safety and accessibility for line restoration and inspection. The voltage classes covered by the distribution vegetation management program are up to 15 kV on the Niagara Mohawk system.

   For the cycle pruning program, a specific base pruning cycle length of 5 years has been set for all Niagara Mohawk circuits based on the general length of the growing season, the growth characteristics of the predominant tree species in each area, and clearance to be created at each pruning site. This is designed to be the optimal length between pruning events to maximize efficiency, reliability and safety.

   The EHTM program uses historic reliability data, coupled with customers served and overhead circuit mileage to prioritize circuits for selection. Besides prioritizing the circuits, each circuit is then partitioned into SAIFI risk segments based on the number of customers served and location of each protection device along the circuit. The hazard tree inspection work is broken down into three intensity levels corresponding to the SAIFI risk segments, with the highest intensity inspection occurring on the section of line closest to the substation outward.

   Since 2002, there have been some enhancements to the vegetation management program. In 2005 the specification was changed to include removal of all overhanging dead, dying or structurally weakened branches to minimize potential interruptions from falling limbs. In 2007 the specification changed again to include additional overhead clearance for pine species by shortening all overhanging pine species boughs beyond the overhead clearance limit to reduce the likelihood of long pine boughs loaded with ice or wet snow from drooping down or breaking onto the conductors. In addition to the specification changes, the annual pruning mileage was revised in 2007. The annual scheduled mileage was increased by 1,000 miles to bring back circuits that were extended past the optimal cycle length of 5 years. The hazard tree removal program has also undergone some improvements. In 2007 the tree outage reduction operation "TORO" was rolled into a system wide enhanced hazard tree mitigation program "EHTM". This program still prioritized removals on three phase sections of feeders, and added a circuit prioritizing tool and criteria for prioritizing circuit segments with customer serviced levels, meaning portions of the circuit with the highest customer count have the highest priority and most intensive inspection.

2. The proposed vegetation management program for 2011 – 2013 will follow the same strategy as currently in use, with the goal of continuous assessment, improvement and evolution. An example of this strategy evolution is the proposed addition of increased hazard tree removals while pruning a circuit. The Company aims to apply knowledge and best practices from the EHTM program and apply them to the cycle pruning program, in an effort to realize reliability benefits similar to those of the EHTM program, without reaching the intensity level and higher cost of the EHTM program, where it is not necessary. As the Company continues to strive for industry leading reliability, efficiency, and safety it will continue to assess and revise the existing strategy as well as continue research, development, and application in the vegetation management field.

3. The tree outage reduction operation, TORO, program started in 2002 and remained in effect until 2007 at which time it was modified to the enhanced hazard tree mitigation (EHTM) program. Even though the EHTM program was directly modeled after TORO, the hazard tree program underwent development and improvement from 2002 to present. The main focus, intensive hazard tree removal along the critical portions of the system, has remained the same, however, in 2008, EHTM was initiated utilizing new tools to help implementation and consistency of risk mitigation. First, instead of simply selecting the top circuits with the highest customers interrupted related to trees, a model was created to look at multiple criteria, such as customers served, customer minutes interrupted per event, events per mile, and cost per change in customer minutes interrupted specific to tree related interruptions. Second, the installations of reclosers and side tap fuses under the REP program since FY07, have provided the ability to split a circuit into risk segments. The implementation of risk segments allows sections of a circuit to be prioritized and assigned risk levels. These tools ensure that work is being done on the correct circuits, at the correct area on a circuit, consistently across the system.

4. Please see Attachment 2 (CVB-4_Attach 2_*VEG REP CY05-CY13 NY v3 Dec '09.xls.*)

5. Please see attached Excel Files, as labeled for the following questions.
    a. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*
    b. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*

c. Attachment 4 (CVB-4_Attach 4_*Miles Trimmed and Trees Removed per Year NY 02-09.xls)*
d. Attachment 4 (CVB-4_Attach 4_*Miles Trimmed and Trees Removed per Year NY 02-09.xls)*
e. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*
f. Attachment 4 (CVB-4_Attach 4_*Miles Trimmed and Trees Removed per Year NY 02-09.xls)*
g. Attachment 4 (CVB-4_Attach 4_*Miles Trimmed and Trees Removed per Year NY 02-09.xls)*
h. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*

6. Please see attached Excel Files, as labeled for the following questions.
    a. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*
    b. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*
    c. Attachment 5 (CVB-4_Attach 5_Miles Trimmed and CPM NY 11-13.xls*)*
    d. Attachment 5 (CVB-4_Attach 5_Miles Trimmed and CPM NY 11-13.xls*)*
    e. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*
    f. Forecasted hazard tree expected removal per year is unavailable as actual field conditions and available budget dictates the number of trees removed. The Company uses an industry leading tree risk analysis protocol to define risk and necessary remediation. As this is applied systematically, actual field conditions, such as tree density, line exposure, tree size and maturity, and forest health make it hard to predict the number of trees expected to remove.
    g. Forecasted average cost for removal of danger trees is also unavailable. Due to the variability in field conditions, the cost to remove danger trees can vary significantly from location to location and site to site. Depending on where reliability concerns are occurring, costs to remove trees may vary greatly.
    h. Attachment 3 (CVB-4_Attach 3_*NY PSC Audit CY2002-2013)*

Name of Respondent:	Date of Reply:
IOP panel / Sara Sankowich	March 1, 2010

Business Plan CY 05 - CY 13
Distribution Veg Mgmt REP View - New York

$'000	CY 05 Budget	CY 05 Actuals	CY 06 Budget	CY 06 Actuals	CY 07 Budget	CY 07 Actuals	CY 08 Budget	CY 08 Actuals	CY 09 Budget	CY 09 Actuals	CY 10 Forecast	CY 11 Forecast	CY 12 Forecast	CY 13 Forecast
OPEX - VM														
Cycle Trimming		12,529,729		16,970,718		22,240,813		22,410,507	19,900,329	24,425,593	28,545,608	28,937,988	29,806,128	30,700,312
Hazard Tree On-Cycle		2,079,105		2,588,159		4,076,753		4,239,284	2,018,636	4,808,963	2,998,894	3,088,861	3,181,527	3,276,973
Hazard Tree Off-Cycle						262,263		260,117	1,162,872	16,524	1,727,568	1,779,395	1,832,777	1,887,760
Worst Feeders						914,478		117,508	424,401	-	630,492	649,407	668,889	688,956
Interim/Spot Trim		222,434		165,983		461,752		1,036,638	251,270	3,010,795	291,751	237,845	233,359	240,359
Sub-T (on-road and off-road costs up to CY 09)		8,767		664		373		486	-	3,167	-	-	-	-
Sub-T (off-road and herbicide portion in Trans Budget as of FY 10)														
Police/Flagman Detail		54,752		17,479		2,809		3,133	-	149	-	-	-	-
Customer Requests		1,342,303		1,529,853		2,289,273		1,783,256	1,241,856	2,068,906	1,844,906	1,900,253	1,957,260	2,015,978
Trouble Maintenance		2,274,773		2,169,192		1,892,108		3,373,401	1,241,856	2,916,080	1,844,906	1,900,253	1,957,260	2,015,978
Other Veg Costs - Contractor		353,156		214,830		238,768		316,975	120,912	395,822	179,627	185,016	190,567	196,284
Other Veg Costs - All Other		2,612,140		2,361,311		2,316,032		2,156,817	1,656,885	2,244,698	2,551,475	2,625,319	2,701,379	2,779,721
CY 09 portion of budget not broken out by activity:									9,177,981					
OPEX - VM Total	**23,755,771**	**21,477,161**	**23,981,763**	**26,018,188**	**27,438,314**	**34,695,422**	**38,248,552**	**35,698,123**	**37,196,998**	**39,890,697**	**40,615,227**	**41,304,338**	**42,529,146**	**43,802,320**

Q: 6-C

Miles Planned to be Trimmed by Division and Year for New York			
Division	2011	2012	2013
East	2,300	2,300	2,300
Central	2,920	2,920	2,920
West	1,980	1,980	1,980
System	7,200	7,200	7,200

Q: 6-D

Forecasted Average Cost per Mile 2011- 2013 for NY			
Division	2011	2012	2013
East	$ 3,833	$ 3,948	$ 4,067
Central	$ 2,738	$ 2,820	$ 2,905
West	$ 3,373	$ 3,474	$ 3,578
System	$ 3,303	$ 3,402	$ 3,504

Date of Request: February 19, 2010
Due Date: March 1, 2010

Request No. RAV-33
NMPC Req. No. NM 54 DPS 50

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirement Panel

Request:

A. Please provide the Company's actual 2002 – 2009 and the historic test year property taxes, broken out between electric, gas, and total. Include both the dollars and annual percentage increases.

B. As shown on Exhibit RRP-4, Schedule 1, Sheets 3 and 4, to determine the rate year ending 12/31/11 electric property tax forecast, the Company used a 3% annual inflation factor and also included additional property taxes on forecasted plant additions. Regarding this methodology, please provide the following information:

1. The basis for the 3% annual inflation factor;
2. The rationale for including additional property taxes on forecasted plant additions;
3. Fully explain why the 3% annual inflation factor, which is almost twice the rate of inflation as measured by the GDP price index, doesn't already inherently provide for additional property taxes on forecasted plant additions;
4. Fully explain why the Company assumed that the property tax rates on existing plant in service would not decline in consideration of the forecasted property being added to the tax rolls. In so doing, fully address the following example: if a county's required property tax collections in 2008 were $10,000,000 on a county-wide property assessment base of $1,000,000,000, the 2008 tax rate would be $1.00 per $1,000 of assessed property; if the 2009 county-wide assessment base increased by $100,000,000 due to NMPC plant additions being added to the assessment rolls, the property tax rate for 2009 would decrease from $1.00 to $0.91 per $100 of assessed property, all else equal [$10,000,000 / $110,000,000];
5. Using the same example as in B.4 above, but assuming the county's 2009 required property tax collections in 2009 were $10,300,000 (i.e., reflecting the annual 3% increase proposed by the Company), the 2009 property tax rate would be to $0.94 per $1,000 of assessed property [$10,300,000 / $110,000,000]

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compared to the Company's methodology which assumes the 2009 property tax rate would be $1.03 per $1,000 of assessed property. Please fully explain why the Company believes this example is flawed since the Company's methodology inherently assumes the tax rate would not decline despite the increase to the assessment rolls.

6. Provide a backcast of the Company's property tax methodology for the years 2007 – 2009. Include supporting calculations and explain all assumptions.

a. Use 2005 actual property taxes, add in the Company's assumed inflation factor and build in property tax increases for actual plant additions to arrive at 2007 property taxes and compare the Company's methodological result with the actual 2007 property taxes.

b. Use 2006 actual property taxes, add in the Company's assumed inflation factor and build in property tax increases for actual plant additions to arrive at 2008 property taxes and compare the Company's methodological result with the actual 2008 property taxes.

c. Use 2007 actual property taxes, add in the Company's assumed inflation factor and build in property tax increases for actual plant additions to arrive at 2009 property taxes and compare the Company's methodological result with the actual 2009 property taxes.

7. To forecast property taxes on forecasted plant additions, the Company used the 2008 "average tax rate per $1,000 of assessed value" as set forth in Exhibit RRP-10, workpapers for Exhibit RRP-4, Schedule 1, workpaper 3. Please provide 2006, 2007 and 2009 "average tax rate per $1,000 of assessed value." Include supporting workpapers.

Response:

A. Please refer to Attachment 1.

B. 1. The 3% annual inflation factor is a composite figure that considers three main issues. First, this inflation factor is a conservative measure of the expected increase in property tax levies by municipalities and schools. "From 2002 to 2007, property taxes rose by 6.8 percent per year on average, while inflation increased at only 2.9 percent per year [CPI]." (2009 Annual Report on Local Governments, Office of the New York State Comptroller, Division of Local Government and School Accountability, November 2009, p. 10). The report goes on to say "Many localities facing rising costs and declining tax revenues may have to turn to the property tax to help make up the difference." Second it includes a measure of the expected increase in assessed value of existing property and a historic average of normal replacement and maintenance build as shown in Exhibit RRP-4, Sheet 4, column (f). Third, using the 2009 net property tax expense as our basis included refunds, which are non-recurring and can not be expected in any future year. While Niagara Mohawk Power Corporation (NMPC) has historically managed to keep its property tax increases below the state average, the CPI, and the GDP price index, the 3 factors referred to above explain why it would be unreasonable to rely on historic experience to forecast the future rate of increase..

B. 2. As shown in Exhibit RRP-4 Sheet 4, the company is not calculating increased property taxes associated with total plant additions. In column (f) a calculation is presented for each of Transmission and Distribution that outlines a historical average of net plant additions. Also in column (f), this historical average is deducted from each year's forecasted net plant additions to derive the capital spending incremental amount that is above the historical average. The additional property taxes requested for plant additions is only on this "incremental amount", not total plant additions. The 3% inflation factor already encompasses this historical average of net plant additions.

B. 3. The 3% annual inflation factor does not already inherently provide for additional property taxes on forecasted plant additions because of the extent of the forecasted plant additions. As mentioned in the response to question B. 1, a historic average of normal replacement and maintenance build is included in the 3% annual inflation factor. However, the forecasted plant additions exceed that historical average by a significant amount each year as shown in Exhibit RRP-4, Sheet 4, column (f).

B. 4. The example provided by staff in question B. 4 is incorrect. In the initial statement, the tax levy is $10,000,000 on a tax base of $1,000,000,000 yielding a tax rate of $1.00 per $1,000 of assessed value. To calculate a tax rate as a value per $1,000 of levy, one must first divide the tax base by 1,000, which in this case would yield 1,000,000. One must then divide the tax levy by the quotient of the previous calculation. In this example, one would divide 10,000,000 by 1,000,000 to derive a tax rate of $10.00 per $1,000 of assessed value.

The second portion of the example assumes an increase in the tax base of $100,000,000. While the math is correct, yielding a tax rate of $.91 per $100 of assessed property, the explanation of that calculation "10,000,000/110,000,000" would actually yield a tax rate of $.09 per $10 of assessed property. More importantly, the measurement is inconsistent with the first part of the example which was a rate per $1,000 of assessed property. For comparison, the rate should be $9.09 per $1,000 of assessed property.

If tax levies were to remain constant, one could logically deduce that the tax rate would decrease against a grown tax base. However, tax levies in New York State have not only increased each year, but have outpaced the Consumer Price Index and the GDP Price Index as supported in the response to question B.1. Furthermore, tax levies are now increasing faster than the tax base which actually decreased from 2008 to 2009. The New York State Office of Real Property Services (ORPS) has two spreadsheets available at www.orps.state.ny.us/reform/local_government_data.cfm named 2008 Local Government Data Spreadsheet and 2009 Local Government Data Spreadsheet. In these two spreadsheets is the equalized full value (fair market value) of all property in the state by municipality for the year in the file name. Excluding New York City, the State's fair market value decreased 1.6% from 1,331,074,594,962 in 2008 to 1,309,858,673,088 in 2009.

B. 5. Please see our response to B.4 above. In addition, staff's calculations in this request are inaccurate. The tax rate following staff's assumed 3% increase in tax levy would be $9.36 per $1,000 of assessed property [10,300,000/(1,100,000,000/1,000)].

This example is flawed because it assumes that the tax base will increase 10% (from 1,000,000,000 to 1,100,000,000) while property tax levies increase at 3%. This would imply that 70,000,000 (70%) of the growth in the tax base (or 7% [70,000,000/1,000,000,000] of the total starting tax base) is due to new build, not replacement or maintenance which would be required to simply maintain the 1,000,000,000 tax base. At that rate, the county would double in size every 14 years (7% / 100%) which is not supported by the growth data from ORPS referenced in response to question B.4

B. 6. Please see our response to B.2 above demonstrating that the company is not calculating increased property taxes associated with total plant additions. Please see Attachment 2 for the calculations and responses to parts a, b and c.

Although this exercise demonstrates the Company's success in managing the rate of increase in its property taxes historically, it would be unreasonable to rely on historic experience to forecast the future rate of increase as discussed in the Company's response to question B. 1

B. 7. Please refer to Attachment 3 in response to this question. When referencing the average tax rate for a given year, note that the year given is the tax roll year, not the calendar year or NMPC fiscal year. The tax roll year is all property tax bills that are based off of the same assessment roll. There are still outstanding property tax bills to be paid on the 2009 assessment roll, so the final average tax rate cannot yet be computed.

Name of Respondent:	Date of Reply:
Shannon Larson & Stephen Adams	March 3, 2010

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	Total Taxes Charged	Electric Taxes Charged	Other Taxes Charged	Gas Taxes Charged	Incr./Decr $ Annual Taxes Electric Only	Incr/Decr % Annual Taxes Electric Only
Test Year (October 2008-September 2009)						
Real Estate	$ 92,578,686	$ 70,695,147	$ 834,042	$ 21,049,496		
Special Franchise	$ 74,229,757	57,198,801	-	17,030,956		
Total	$ 166,808,443	$ 127,893,949	$ 834,042	$ 38,080,453		
Calendar 2009						
Real Estate	$ 92,331,929	$ 71,611,054	$ 874,645	$ 19,846,231		
Special Franchise	$ 74,031,907	57,966,983	-	16,064,924		
Total	$ 166,363,836	$ 129,578,037	$ 874,645	$ 35,911,155	$ 2,391,460	1.88%
Calendar 2008						
Real Estate	$ 91,095,306	$ 70,703,731	$ 810,643	$ 19,580,932		
Special Franchise	$ 72,147,219	56,482,846	-	15,664,374		
Total	$ 163,242,525	$ 127,186,577	$ 810,643	$ 35,245,306	$ (1,600,646)	-1.24%
Calendar 2007						
Real Estate	$ 89,819,999	$ 71,209,859	$ 808,671	$ 17,801,469		
Special Franchise	$ 71,971,705	57,577,364	-	14,394,341		
Total	$ 161,791,704	$ 128,787,223	$ 808,671	$ 32,195,810	$ (1,649,830)	-1.26%
Calendar 2006						
Real Estate	$ 90,770,702	$ 71,961,017	$ 821,292	$ 17,988,392		
Special Franchise	$ 73,095,008	58,476,036	-	14,618,972		
Total	$ 163,865,710	$ 130,437,053	$ 821,292	$ 32,607,364	$ (7,532,209)	-5.46%
Calendar 2005						
Real Estate	$ 95,748,058	$ 75,952,714	$ 824,105	$ 18,971,239		
Special Franchise	$ 77,507,117	62,016,548	-	15,490,569		
Total	$ 173,255,176	$ 137,969,263	$ 824,105	$ 34,461,808	$ 3,649,752	2.72%
Calendar 2004						
Real Estate	$ 92,390,015	$ 82,734,801	$ 652,813	$ 9,002,401		
Special Franchise	76,047,765	51,584,710	-	24,463,055		
Total	$ 168,437,780	$ 134,319,511	$ 652,813	$ 33,465,456	$ 5,728,430	4.45%
Calendar 2003						
Real Estate	$ 87,889,813	$ 81,483,727	$ 650,297	$ 5,755,789		
Special Franchise	73,807,973	47,107,354	-	26,700,619		
Total	$ 161,697,786	$ 128,591,081	$ 650,297	$ 32,456,408	$ 8,152,245	6.77%
Calendar 2002						
Real Estate	$ 93,921,212	$ 43,915,044	$ 25,376,230	$ 24,629,938		
Special Franchise	81,812,603	76,523,792	-	5,288,811		
Total	$ 175,733,815	$ 120,438,836	$ 25,376,230	$ 29,918,749		

Question B. 6 (a)		
2005 Actual Property Taxes	$ 137,969,263	Exhibit 1, Line 38
3 % Annual Inflation Factor	4,139,078	
Tax impact of Plant Additions Surge	(516,280)	WP-1 Line 9 plus Line 20
Total 2007 Methodological Result	$ 141,592,061	
Actual 2007 Results	$ 128,787,223	

Question B. 6 (b)		
2006 Actual Property Taxes	$ 130,437,053	Exhibit 1, Line 33
3 % Annual Inflation Factor	3,913,112	
Tax impact of Plant Additions Surge	387,055	WP-1 Line 10 plus Line 21
Total 2008 Methodological Result	$ 134,737,220	
Actual 2008 Results	$ 127,186,577	

Question B. 6 (c)		
2007 Actual Property Taxes	$ 128,787,223	Exhibit 1, Line 28
3 % Annual Inflation Factor	3,863,617	
Tax impact of Plant Additions Surge	443,628	WP-1 Line 11 plus Line 22
Total 2009 Methodological Result	$ 133,094,468	
Actual 2009 Results	$ 129,578,037	

Date of Request: February 23, 2010
Due Date: March 5, 2010

Request No. CVB-5
NMPC Req. No. NM 76 DPS 53

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christian Bonvin

TO: Infrastructure and Operations Panel

Request:

1. How often does the Company run the Recloser Model associated with the recloser application strategy?
2. Exhibit_IOP-14, Schedule 2, sheet 94 states that the Company plans to install 100 reclosers per year going forward. Does the Company prioritize recloser installation based solely on the results of the Recloser Model? If not, please explain what other factors are considered to determine where the 100 reclosers per year are to be installed.
3. Please provide the information as it relates to historic installation of reclosers under the recloser application strategy:
   A. The total number of 15kV class radial feeders that have been identified on the system as candidates to receive one or more recloser based on the Recloser Model.
   B. The number of feeders identified for reclosers based on methods other than the Recloser Model.
   C. Number of feeders that had one or more reclosers installed on them, by year, for FY08, FY09, and FY10.
   D. Number of feeders forecasted to have a recloser installed on them for each fiscal year in the five year budget.
   E. Average number reclosers installed per feeder for FY08, FY09, and FY10, by year.
   F. Percentage of recloser installations that were for single phase applications.
4. What is the number of reclosers to be installed in each fiscal year in the five year budget associated with projects C13266, C13267, and C13268?
5. What is the average number of reclosers to be installed per feeder for each fiscal year in the five year budget?

Response:

Form 103

1) The Company updates the recloser model once per year.

2) The recloser model is not the only means of selecting recloser locations. The Company utilizes the output of the recloser model, feeder hardening feeders, Engineering Reliability Review (ERR) feeders and the NYSPSC worst performing feeder lists filed in the annual Electric Service Reliability Report, in accordance with Case 90-E-1119, to select and prioritize locations for recloser installation.

   As the program progresses, all remaining 13.2kV radial feeders that currently do not have a recloser (of which there are approximately 365 at this time) will be evaluated for recloser installation opportunities. In addition, there are many 5kV feeders that will be evaluated in rural areas that are good candidates for recloser installations due to their length.

3)

A) The current output from the recloser model indicates there are 253 candidate feeders for recloser installations. Of these, 239 are 13.2kV feeders. Historic data is not maintained from the recloser model since it has been updated a number of times since its inception.

B) The number of feeders identified by methods other than the recloser model per year is as follows:

FY08: 21 Feeder Hardening feeders
24 Engineering Reliability Review feeders

FY09: 22 Feeder Hardening feeders
41 Engineering Reliability Review feeders
8 NYSPSC Worst Performing feeders

FY10: 16 Feeder Hardening feeders
62 Engineering Reliability Review feeders
9 NYSPSC Worst Performing feeders

C) The number of feeders with one or more recloser recommend per year is as follows:

FY08: 68 feeders total	25 feeders with multiple reclosers
FY09: 105 feeders total	15 feeders with multiple reclosers
FY10: 118 feeders total	50 feeders with multiple reclosers

D) Eighty-two feeders will have recloser installations in FY11. Specific recloser locations are typically finalized 3 to 6 months prior to the beginning of the fiscal year, therefore, only FY11 data can be provided for this response.

E) The average number of reclosers installed per feeder is as follows:

FY08: 100 reclosers/68 feeders = 1.47 per feeder
FY09: 160 reclosers/105 feeders = 1.52 per feeder
FY10: 211 reclosers/118 feeders = 1.78 per feeder

F) National Grid's recloser program is presently focused on the installation of three phase units. However, the Company has installed seven single phase S&C Trip Saver reclosers under a pilot program. These units fit into a standard S&C fuse cutout holder and are designed to 'fuse save' for temporary faults. It is anticipated that the installation of these types of single phase installations will be included as part of the program once the pilot is validated.

4). The recloser budget by Division is typically set in the July/August timeframe, prior to the beginning of the fiscal year, when the feeder hardening, ERR and worst performing feeder lists become available. As such, only an FY11 breakdown of data can be provided.

<u>FY11 Capital Budget:</u>

C13266 – East	$1,650,000	33 reclosers
C13267 - Central	$1,650,000	33 reclosers
C23268 – West	$1,700,000	34 reclosers

5) There will be 1.22 reclosers installed per feeder in FY11. As stated in the response to question 3D above, specific locations are selected on an annual basis and cannot be provided for FY12 through FY15.

<u>Name of Respondent:</u>
Infrastructure and Operations Panel/Rob Sheridan

<u>Date of Reply:</u>
March 4, 2010

Date of Request: February 23, 2010
Due Date: March 5, 2010

Request No. RAV-37
NMPC Req. No. NM 78 DPS 55

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Rate Design, Customer and Markets Panel

Request:

A. Please provide a summary of actual Economic Development discounts for each of the years 2002 – 2009 and the historic test year, broken down by type of discount (EZR, SC 11/12, PFJ, SC7, etc). Provide total discounts for each of the years.

B. Please provide a summary of forecasted Economic Development discounts for each of the three rate years, broken down by type of discount (EZR, SC 11/12, PFJ, SC7, etc). Provide total discounts for each of the years. Explain how these forecasted amounts were determined.

C. Please provide the actual Economic Development Program costs for each of the years 2002 – 2009 and the historic test year, broken out between external, internal and total. Briefly describe the types of internal costs included these dollar amounts.

D. Please provide the total forecasted Economic Development Program costs for each of the three rate years, broken out between external, internal, and total. Explain how these forecasted amounts were determined.

E. For each of the three rate years, what is the amount of base rate allowance that will be credited to the Company's proposed Economic Development deferral account, by type (i.e., discounts and program costs) and in total? Include exhibit references for each amount.

F. On page 119 of your pre-filed direct testimony, you recommend that the grant programs "be maintained at the current level of funding of $12.5 million per year." Please indicate if you agree that the referenced $12.5 million per year built into MJP base rates was intended to cover economic development program costs and incremental discounts, rather than just program costs as your pre-filed testimony suggests. If you disagree, fully explain the basis of your disagreement and provide supporting documentation from the MJP (MJP terms, work papers, statements in support, testimony, etc).

Response:

Per a conversation between Pamela Dise and Robert Visalli on 2-24-2010 parts A and B of this request are withdrawn as they are duplicative with RAV-32. In addition, Mr. Visalli changed the time period requested for Part C to 2005 – 2009.

C. Actual Economic Development Program Costs:

	CY 2005	CY 2006	CY 2007	CY 2008	CY 2009	Historic Test Year
External	$5,069,782	$4,277,226	$5,919,860	$6,228,724	$3,692,686	$4,757,707
Internal (Non-Labor)	501,311	525,900	563,743	407,730	452,624	433,628
Total	$5,571,093	$4,803,126	$6,483,603	$6,636,454	$4,145,310	$5,191,335

Internal costs represent all non-labor operating expenses associated with the Company's Economic Development activities, including consulting, marketing, advertising, research services and organization/event sponsorships and dues.

D. Forecast Economic Development Program Costs:

	2011	2012	2013
External	$12,500,000	$12,500,000	$12,500,000
Internal (Non-Labor)	447,567	455,624	464,280
Total	$12,947,567	$12,955,624	$12,964,280

The external cost forecast was developed by analyzing current levels of activity and reviewing the list of projects that have been approved, but not yet completed. There is currently an accumulated balance of approximately $8 million for projects for which the funds have been committed but not yet reimbursed to the customer. In addition the Company anticipates an increase in demand for the Renewable Energy & Economic Development program, which is a new initiative approved as part of the Company's 2010 EDP. Finally, the Company plans to introduce a new Clean Tech Incubation Program in 2011 which will also contribute to an increase in spending over recent actual spending.

The internal cost forecast was developed by taking the historic test year and applying inflation factors taken directly from Exhibit RRP-7, Summary, Sheet 1 of 1. The Company assumed that the forecast level of spending in this area would be maintained throughout the rate period with the exception of inflationary factors.

E. As indicated in the Revenue Requirements Panel Testimony on page 91 of 110, the Company proposes to continue the deferral treatment of the Economic Development Fund. In addition, on Exhibit RRP-8, Schedule 2, Sheet 1 of 1, the Company presents the proposed amount for rate allowance for the Economic Development Deferral Mechanism totaling $44,363,100 for each year of the rate plan. Below is the breakout of the proposed deferral amount.

	2011	2012	2013
Economic Development Zone Discounts	$18.6	$18.6	$18.6
SC11/12 (Flex Rate) Discounts	13.3	13.3	13.3
Economic Development Fund	12.5	12.5	12.5
Total	$44.4	$44.4	$44.4

Source: Economic Development Zone Discounts and SC11/12 Discounts, RDCM-4, Schedule 2, 3 and 4. Economic Development Fund, RRP-2, Schedule 35, Sheet 4 of 4.

F. The Company agrees that it recovers certain forecast rate discounts pursuant to section 1.2.4.7 of the MJP, and that it may recover up to $12.5 million in costs associated with certain grant programs and incremental rate discounts (in excess of forecasts) pursuant to section 1.2.10 of the MJP. Rate discounts not recovered in either of these ways are presently deferred for future recovery pursuant to section 1.2.4.7 of the MJP.

Name of Respondent:
Susan Crossett

Date of Reply:
March 5, 2010

Date of Request: February 24, 2010
Due Date: March 8, 2010

Request No. AJR-2
NMPC Req. No. NM 79 DPS 56

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Aric Rider

TO: Infrastructure and Operations Panel

Request:

A. Provide a detailed timeline that describes the Company's annual electric capital expenditures budgeting process. The flow chart/timeline of the preparation and approval process should include a description and title of the Company personnel responsible for each step, approximate dates, and relevant sign-offs.

B. Referring to Exhibit ____(IOP-1), Schedule 5, Sheet 2, indicate whether the proposed annual electric capital expenditure budgets for fiscal years ending 2011, 2012, 2013, and 2014 were approved by the Board of Directors.

C. Referring to Exhibit ____(IOP-1), Schedule 5, Sheet 2, indicate whether the proposed annual electric capital expenditure budgets for fiscal years ending 2011, 2012, 2013, and 2014 were approved by Company management.

D. Provide the electric capital expenditure budgets presented to the Board of Directors for fiscal years ending 2006, 2007, 2008, 2009 and 2010, in the same format as Exhibit ___(IOP-1), Schedule 5, Sheet 2.

E. Provide the electric capital expenditure budgets approved by the Board of Directors for fiscal years ending 2006, 2007, 2008, 2009 and 2010, in the same format as Exhibit ___(IOP-1), Schedule 5, Sheet 2.

F. Provide the actual electric capital expenditures for fiscal years ending 2006, 2007, 2008, 2009 and 2010, in the same format as Exhibit ___(IOP-1), Schedule 5, Sheet 2.

Response:

A. Please see Attachment 1(AJR-2_Attach 1) which describes the Transmission and Distribution electric capital spending plan development process.

B. As stated in the response to NM 63 MI-10 MM-10, each year the Company develops a multi-year business plan. The governance process concludes with the National Grid plc Board of Directors approving the first year of the plan, which for the current forecast period is April 1, 2010 through March 31, 2011, and the Board notes the remaining years of the plan. The Company expects the FY11 budget will be considered for approval at the March 2010 Board meeting. It should be noted that IOP-1, schedule 5, sheet 2 relates to the System Capacity and Performance spending category, which is only a subset of Niagara Mohawk's proposed capital expenditure level.

C. As stated in the response to NM 63 MI-10 MM-10, the Company's Executive Committee has approved the capital investment plan included in the rate case. It should be noted that IOP-1, schedule 5, sheet 2 relates to the System Capacity and Performance spending category, which is only a subset of Niagara Mohawk's proposed capital expenditure level.

D, E & F.

For the budget years requested, the budget that has been presented to the Board has been approved without changes. It should be noted that the Board approves a budget that is an aggregate of individual regulatory jurisdiction budgets rolled up by Line-of Business.

The Company is only able to provide FY10 data in the format similar to Exhibit__(IOP-1) Schedule 5, Sheet 2 as it was the first year that budgeted projects were assigned a program/strategy in the spending rationale categories, see Attachment 2 (AJR-2_Attach 2). Attachment 2 also contains a preliminary electric capital expenditures budget for FY10 as presented in the January, 2009 CIP filing, as well as the final FY10 budget presented to and approved by the National Grid plc Board of Directors.

The budget that was presented and approved by the Board and actual spend for FY06 through FY10 is provided in Attachment 3 (AJR-2_Attach 3) in an alternative format to Exhibit___(IOP-1), Schedule 5, Sheet 2 as such budget categories were not historically assigned to projects prior to FY10.

- FY08-FY10 final budget and actuals are provided by spending rationale – figures reported are fiscal year end in our current quarterly reporting format. FY10 figures are taken from the 3Q report submitted to the PSC in February 2010.
- FY06 and FY07 were not reported in spending rationale format as they were never originally reported/mapped in this way.

<u>Name of Respondent:</u> Mark Eddy

<u>Date of Reply:</u> March 8, 2010

Transmission & Distribution Fiscal Year Capital Spending Plan Development Schedule of Key Deliverables

	Task Name	Duration	Start Date	Finish Date	Task Initiator/Comments
	Year Round Activity				
1	Identify candidate projects and programs based upon planning studies, strategies, ERR's, PIWs, damage/failure and I&M inspection results.	April - March	Continuous		Project and Program sponsors and reports from field
2	Update TRAC & SRAC (capital projects list) financial forecasts to include all new programs and projects from pre-strategy phase to project close-out. All projects include Risk Score.	April - March	typically 2nd week of month	end of month	Program Management working with Investment Management
3	Review Monthly YTD Actuals vs budget	April - March	typically 2nd week of month		Finance and Investment Management
4	Update and Maintain Transmission and Distribution Related Projects Listing	April - March	typically 2nd week of month		Transmission and Distribution Investment Management with Transmission and Distribution Project Management
5	Review and provide reforecasted 2- year outlook on capital expenditures to finance	Quarterly			Finance
6	**April**				
7	Develop preliminary blanket spending levels for Upcoming FY.	1 month	1-Apr	End-April	Investment Management, LTP and Program Mgt.. Input from other depts. including Finance, Opns., Design, and Load/Economic Forecasting
8	April QPR: Primary focus: Senior Management update on most important action items to deliver new plan.	Meeting	typically 3rd week of month		QPR information is based on the quarterly financial forecast and includes updates for both financial and operational issues. Senior EDG leadership and Corporate are present at the meeting.
	May				
9	Develop Preliminary List of Project Proposals for upcoming 5 Fiscal Years.	1 month	1-May	End-May	Investment Management to develop list with assistance from Asset Sponsors. List will be based upon Projects listed in latest Budget/Forecast file, in PowerPlant (initiated or open status), and as submitted by asset sponsors. Project information to include description, scope, justification, cash flows, and total capex, opex, and removal costs.
	June				

	Task Name	Duration	Start Date	Finish Date	Task Initiator/Comments
10	Assemble Baseline 5 year FY Spending Plan	1 week	1-Jun	Mid-June	Investment Management to issue plan to asset sponsors and project management Baseline version will reflect first pass funding for blankets, programs, carryover specifics, and 5-year plan specifics. Baseline to include capex, opex, and removal funding. Out-years of the plan to include Blanket, Program, and Specific Projects, and placeholders to balance to defined capex totals for out-years.
11	Check Spending vs. commitments in each state	1 week	Mid-June	End-June	Investment Management
12	Finalize Reliability Enhancement Program Initiatives	1 week	Mid-June	End of July	Asset Strategy to lead this effort with assistance from Investment Management. Asset Strategy to be provided with the 5-year preliminary funding for programs.
13	Finalize Blanket Project Spending Levels	2 days	Mid-June	End-June	Investment Management with Finance.
14	Confirm Specific Project and Program Proposals	1 week	Mid-June	End of July	Individual project sponsors are responsible for reviewing their proposed projects. Project information in PowerPlant to include description, scope, justification, cash flows, and total capex, opex, and removal costs
15	Project Data Review & Resolution	1 week	Mid-June	End-June	Identify any projects with missing or incorrect data. Develop and submit data for such projects.
16	Check Capex related Opex and Removal Spending and Forward preliminary cut to Finance	1 week	Mid-June	End-June	Investment Management with input from Program Mgt. To also include pure Opex REP initiatives.
	July				
17	Business Plan kick-off. Finance provides guidance paper for 5-year Business Plan. Paper describes the process, defines deliverables, submission dates, approval process and specific guidance regarding inflation assumptions, payroll and staffing levels.	1 month	1-Jul	1-Aug	Transmission Finance
18	Global Investment Management provides project risk scoring templates overview of process for cross line of business review.	1 month	1-Jul	1-Aug	Global Investment Management
19	Review Matrix Scores of Programs and Projects	1 week	1st week in July.	1st week in July	Investment Management will publish risk scores. Investment Management and will review the scoring with each Asset Sponsor
20	Draft Proposed & Prioritized Spending Plan	1 week	1st week in July	1st week in July	Investment Management

	Task Name	Duration	Start Date	Finish Date	Task Initiator/Comments
21	Spending Plan Review and Challenge Sessions	3 weeks	2nd week in July	End-July	Challenge sessions. The Risk Scoring, scope, justification, schedule, and cash flows for each project will be subject to review and questioning. Project sponsors need to be prepared to defend their proposals.
22	July QPR: Primary Focus: Senior Management review of current 2 -year outlook as compared with current Business Plan with a high level indication for changes expected during upcoming 5 year Business Plan Cycle and forecast update.	Meeting	typically 3rd week of month		Corporate
23	Coordinate Transmission and Distribution Project Schedules	2 days	typically 1st week in July		Investment Mgt meets with Trans Inv. Mgt to synchronize project need dates, cash flows, administrative requirements, and resolve any conflicts
	August				
24	Develop Capital Business Plan from current TRAC extract. Include new "placeholders" for programs and projects not yet at strategy phase. Verify financial forecasts.	1 month	1-Aug	25-Aug	Transmission Investment Management
25	Confirm matrix Risk Scores for Spending Plan Programs and Projects.	1 month	1-Aug	25-Aug	Transmission Investment Management
26	Finalize proposed capex forecast, Cost of Removal and OPEX related to capex expenditures.	1 month	1-Aug	25-Aug	Transmission Investment Management
27	Load proposed budget into budget system and investment management templates for Transmission Finance and Global Investment Management review.	1 week	25-Aug	31-Aug	Transmission Investment Management
28	Finalize the Draft 5-Year Spending Plan	2 weeks	1st week in Aug.	Mid-Aug	Investment Management
29	Submit the Draft5-Year Spending Plan for management review and approval	1 week	Mid-Aug.	End-Aug.	Investment Management
	September				
30	Creation and submission of full LOB Business Plan financials and commentaries on key themes to Corporate	1 month	1-Sep	30-Sep	Finance
31	Draft 5-Year Spending Plan Forwarded to Finance and to Program Mgt. for preliminary resourcing		End-Aug.	1-Sep	Investment Management
	October				
32	October QPR: Primary focus - Senior Management review and challenge on LOB's proposed Business Plan.	Meeting	typically 3rd week of month		Corporate
	November - December				

	Task Name	Duration	Start Date	Finish Date	Task Initiator/Comments
33	Conduct true-up checks of blankets, programs, and project forecast spending of Current Year vs. Upcoming Budget. Incorporate any Management Changes to spending plan. Incorporate or Task Line any necessary adjustments into Spending Plan.	1 week	Mid-Dec. & Early-March	End-Dec. & Mid-March	Investment Management
34	Review and agree on revision by LOB based on Executive feedback through the Global Investment Planning Process.	Meeting			Finance with Investment Management
	January				
35	January QPR: Senior Management update on current FY opex and capex plan and review of draft proposed Business Plan	Meeting	typically 3rd week of month		Finance with Investment Management
36	Prepare detailed opex and capex Work Plan for resourcing by Transmission Work Delivery and Service Provider work forces	1 month	2-Jan	31-Jan	Transmission Investment Management
	February - March				
37	Update Spending Plan Spreadsheet functionality. Update Program master spreadsheets and synchronize with Spending Plan preliminary entries.	1 month	February	Early-March	Investment Management
38	Review NY TxD Project List and Update Spending Plan. Incorporate TxD projects and programs into overall Spending Plan Budget Spreadsheet	1 month	February	Early-March	Investment Management with Asset Sponsors and Project Management
39	Develop Project Estimating and Scheduling Approach for 5-Year Spending Plan	1 month	February	End-February	Investment Management to work with Project Management & Planning Base upon similar completed projects to be applied to proposed projects as starter to reserve cash flows in plan.
40	Finalize Draft Business Plan for submission to National Grid Board for approval	Meeting	typically 3rd week in February		Finance
41	Review detailed opex and capex Work Plan with Transmission Work Delivery and Service Provider work forces to verify ability to deliver	2 months	1-Feb	31-Mar	Transmission Investment Management
42	Coordinate Transmission and Distribution Project Schedules	2 days	typically 1st week in March		Investment Mgt meets with Trans Inv. Mgt to synchronize project need dates, cash flows, administrative requirements, and resolve any conflicts
	March				
43	Confirm preliminary Program spending levels for Upcoming fiscal year and remaining out-years of 5-year spending plan.		1st week March	End-March	

	Task Name	Duration	Start Date	Finish Date	Task Initiator/Comments
44	Develop Matrix Scores for Spending Plan Line Items and Programs	On-going through August	1st week March	End-June	Investment Management and Asset Sponsors. Will include process rollout and any instructions/training. Use existing scores as part of Global scoring exercise. New projects will need to be scored.
45	National Grid Board approves Budget Year	Meeting	late March		National Grid Board
46	Conduct true-up checks of blankets, programs, and project forecast spending of Current Year vs. Upcoming Budget. Incorporate any Management Changes to spending plan. Incorporate or Task Line any necessary adjustments into Spending Plan.	1 week	Mid-Dec. & Early-March	End-Dec. & Mid-March	Investment Management
	April				
47	Commence new Fiscal Year				

Line Of Business	Spending Rationale	Strategy for AJR-2	Preliminary FY10 Budget as Presented in Jan 2009 CIP	Final FY10 Budget
DIST	Asset Condition	Addressed by Multiple Overhead Strategies	359,000	441,000
		Addressed by Multiple Substation Strategies	142,000	748,000
		Addressed by Multiple Underground Strategies	2,366,000	911,000
		Distribution Line Transformer	2,151,000	1,411,000
		Distribution Overarching	-	255,000
		EMS - Strategy to be written	200,000	614,000
		Engineering Reliability Review	-	1,108,000
		Feeder Hardening	6,591,000	4,576,000
		Indoor Substation	11,405,000	15,454,000
		Manhole/Vault/Miscellaneous UG Equipment (Capital related to I&M)	2,103,000	2,241,000
		Manholes and Vaults	1,167,000	1,299,000
		Open Wire Primary	3,413,000	471,000
		Open Wire Primary	-	200,000
		Planning - to be written	452,000	781,000
		Primary Underground Cable	702,000	996,000
		Primary Underground Cable	-	500,000
		Blanket	7,661,000	8,310,000
		Substation Battery and Related	374,000	378,000
		Substation Battery and Related	-	250,000
		Substation Capacitor & Switch	234,000	50,000
		Substation Circuit Breaker & Recloser	1,511,000	425,000
		Substation Circuit Breaker/Recloser	-	1,400,000
		Substation Circuit Switcher	630,000	671,000
		Substation Disconnect & MOD	47,000	50,000
		Substation Metal Clad Switchgear	-	800,000
		Substation Metalclad Switchgear	2,338,000	1,000,000
		Substation Overarching	-	627,000
		Substation Power Transformer	2,244,000	1,637,000
		Substation Power Transformer	-	50,000
		Substation Reactor	94,000	100,000
		Substation Regulator & Reactor	234,000	249,000
		UG Getaway Cable	570,000	307,000
		URD Cable Replacement	234,000	249,000
		Wood Pole	4,583,000	3,814,000
		Wood Pole/ Miscellaneous OH Equipment (Capital related to I&M)	17,580,000	18,723,000
		Pockets of Poor Performance	561,000	-
	Asset Condition TOTAL		**69,946,000**	**71,096,000**
	Damage/Failure	Damage/Failure	1,073,000	1,850,000
		Blanket	17,128,000	18,241,000
	Damage/Failure TOTAL		**18,201,000**	**20,091,000**
	Other	Blanket	607,000	671,000
		Telecommunications	1,105,000	1,168,000
		Distribution Line	2,057,000	507,000
	Other TOTAL		**3,769,000**	**2,346,000**
	Statutory/Regulatory	New Business	-	3,332,000
		Public Requirements	-	2,926,000
		Blanket	79,167,000	82,458,000
		Statutory./Regulatory	6,729,000	5,275,000
	Statutory/Regulatory TOTAL		**85,896,000**	**93,991,000**
	System Capacity & Performance	Addressed by Multiple Overhead Strategies	823,000	150,000
		Addressed by Multiple Substation Strategies	-	100,000
		Distribution Line Regulator	-	150,000
		EMS - Strategy to be written	748,000	48,000
		Engineering Reliability Review	-	1,674,000
		Open Wire Primary	140,000	174,000
		Open Wire Primary	-	100,000
		Planning - to be written	37,819,000	23,231,000
		Planning Criteria	-	7,160,000
		Recloser Application	7,482,000	7,762,000
		Blanket Load Relief	2,531,000	2,695,000
		Blanket Reliability	6,979,000	7,432,000
		Engineering Reliability Review	3,220,000	4,067,000
		Storm Damage	1,350,000	1,437,000
		Substation Circuit Breaker & Recloser	-	275,000
		Substation Mobile Transformer - to be written	449,000	40,000
		Substation Power Transformer	-	150,000
	System Capacity & Performance TOTAL		**61,541,000**	**56,645,000**
DIST Total			**239,353,000**	**244,169,000**
TxD	Asset Condition	Addressed by Multiple Overhead Strategies	2,068,000	619,000
		Addressed by Multiple Substation Strategies	-	141,000
		Distribution Line Regulator	-	350,000
		Indoor Substation	1,000,000	1,258,000
		Open Wire Primary	-	200,000
		Planning - to be written	1,810,000	600,000

		Blanket	1,242,000	1,242,000
		Substation Capacitor & Switch	500,000	200,000
		Substation Circuit Breaker & Recloser	2,645,000	420,000
		Substation Metalclad Switchgear	1,500,000	4,800,000
		Substation Power Transformer	-	160,000
		Substation Reactor	1,811,000	700,000
		Subtransmission Line Overarching	-	4,205,000
		Subtransmission Underground Cable	4,079,000	3,882,000
		Wood Pole	9,063,000	10,022,000
		Wood Pole/ Miscellaneous OH Equipment (Capital related to I&M)	4,500,000	4,500,000
	Asset Condition TOTAL		**30,218,000**	**33,299,000**
	Damage/Failure	Blanket	1,335,000	497,000
	Other	Allowance for Schedule Change	(2,100,000)	(4,830,000)
	Statutory/Regulatory	New Business	-	451,000
		Public Requirements	-	206,000
		Blanket	386,000	386,000
		Statutory./Regulatory	1,500,000	1,310,000
	Statutory/Regulatory TOTAL		**1,886,000**	**2,353,000**
	System Capacity & Performance	Addressed by Multiple Overhead Strategies	350,000	500,000
		Planning - to be written	1,225,000	1,075,000
		Planning Criteria	-	2,200,000
		Relay Protection - to be written	50,000	50,000
		Blanket Load Relief	99,000	99,000
		Blanket Reliability	615,000	615,000
		Substation Mobile Transformer - to be written	1,300,000	2,000,000
		Subtransmission Underground Cable	3,039,000	159,000
	System Capacity & Performance TOTAL		**6,678,000**	**6,698,000**
TxD Total			**38,017,000**	**38,017,000**
Grand Total			**277,370,000**	**282,186,000**

Niagara Mohawk Power Corporation d/b/a National Grid			Attachment 2 - Part B
Transmission Spending Rationale	**Program**	**Preliminary FY10 Budget as Presented in Jan 2009 CIP**	**FY09/10 Board Approved**
Asset Condition	ATB Strategy Total	590,000	590,000
	Battery Strategy Total	330,000	330,000
	Leeds SVC Strategy Total	2,200,000	2,200,000
	115kv Substation Bulk Power System Upgrades Total	100,000	100,000
	Other Asset Condition Total	(28,175,206)	(45,175,206)
	Other System Capacity & Performance Total	200,000	200,000
	Overhead Line Refurbishment Program Total	829,904	829,904
	Polymer Insulator Replacement Total	1,329,999	1,329,999
	Refurbishment (Rehabilitation) Total	8,380,000	8,380,000
	Relay Replacement Strategy Total	762,000	762,000
	RHE Breaker Replacement Total	520,000	520,000
	Shield Wire Strategy Total	11,319,000	11,319,000
	Steel Tower Strategy Total	20,752,071	20,752,071
	Substation Rebuilds Total	13,766,337	13,711,337
	System Capacity & Performance Total	1,039,279	1,039,279
	U Series Relay Strategy Total	30,000	30,000
Asset Condition Total		**33,973,384**	**16,918,384**
Damage/Failure	Damage/Failure	13,987,150	13,987,150
	Wood Pole Strategy	1,150,000	1,150,000
Damage/Failure Total		**15,137,150**	**15,137,150**
Other	Other	(200,000)	(200,000)
		3,466,832	3,571,832
Other Total		**3,266,832**	**3,371,832**
Statutory/Regulatory	Frontier Region Total	25,658,112	25,658,112
	Generation Total	(540,000)	(540,000)
	Load Total	(352,440)	(352,440)
	Luther Forest Total	13,098,000	13,098,000
	Other Statutory/Regulatory Total	50,800	50,800
	Reliability Criteria Compliance Total	5,995,498	5,995,498
	Clay Station Rebuild Total	317,868	317,868
	Clearance Strategy Total	1,984,175	1,984,175
	Digital Fault Recorder Strategy Total	2,674,046	2,674,046
	Other Statutory/Regulatory Total	1,068,001	1,068,001
	RTU Strategy Total	2,950,000	2,950,000
	Other Syst Capacity & Performance Total	24,000	24,000

Transmission Spending Rationale	Program	Preliminary FY10 Budget as Presented in Jan 2009 CIP	FY09/10 Board Approved
Statutory/Regulatory Total		**52,928,060**	**52,928,060**
System Capacity & Performance	System Capacity & Performance Total	140,000	140,000
	3A/3B Tower Strategy Total	80,000	80,000
	Circuit Switcher Strategy Total	-	-
	Other System Capacity & Performance Total	8,474,575	8,424,575
System Capacity & Performance Total		**8,694,575**	**8,644,575**
Grand Total		**114,000,000**	**97,000,000**

AJR-2 Attachment 3

Niagara Mohawk Electric plant Proposed Budget and Approved Budget vs Actual FY2006 through FY2010 ($m)

		FY06 Proposed Budget	[illegible]	FY06 Actuals	FY07 Proposed Budget	[illegible]	FY07 Actuals	FY08 Proposed Budget *	[illegible]	FY08 Actuals *	FY09 Proposed Budget *	[illegible]	FY09 Actuals *	FY10 Proposed Budget *	[illegible]	FY10 Forecasted Actuals *
DISTRIBUTION	Asset Condition	xx	xx	xx	xx	xx	xx	32.6	32.6	31.6	41	41.0	50.9	43.9	43.9	46.7
	Damage Failure	xx	xx	xx	xx	xx	xx	15.4	15.4	16.2	16.1	16.1	20.3	22	22.0	21.0
	Other/Non-Infrastructure	xx	xx	xx	xx	xx	xx	1.9	1.9	(2.0)	-15.8	(15.8)	2.1	4.2	4.2	2.8
	Statutory/Regulatory	xx	xx	xx	xx	xx	xx	118.1	118.1	105.6	101.9	101.9	96.6	118.6	118.6	118.2
	System Capacity & Performance	xx	xx	xx	xx	xx	xx	38.1	38.1	42.6	69.9	69.9	46.4	55.5	55.5	53.4
	Total	135.5	135.5	160.4	169.5	169.5	182.1	206.1	206.1	194.0	213.1	213.1	216.3	244.2	244.2	242.1
SUB-TRANSMISSION	Asset Condition	xx	xx	xx	xx	xx	xx	20.2	20.2	21.3	22.7	22.7	19.2	26.4	26.4	25.0
	Damage Failure	xx	xx	xx	xx	xx	xx	1.3	1.3	2.2	1.9	1.9	3.9	2.1	2.1	3.3
	Other/Non-Infrastructure	xx	xx	xx	xx	xx	xx	-8.9	(8.9)	-	-11.8	(11.8)	-	-5.9	(5.9)	(1.0)
	Statutory/Regulatory	xx	xx	xx	xx	xx	xx	2.5	2.5	(0.9)	6.7	6.7	4.5	9.3	9.3	7.6
	System Capacity & Performance	xx	xx	xx	xx	xx	xx	2.9	2.9	3.8	8.5	8.5	3.8	6.1	6.1	6.4
	Total	8.2	8.2	12.3	27	27.0	23.8	18	18.0	26.4	28	28.0	31.4	38	38.0	41.3
TRANSMISSION	Asset Condition	xx	xx	xx	xx	xx	xx	12.2	12.2	15.1	22.7	22.7	14.6	16.9	16.9	49.2
	Damage Failure	xx	xx	xx	xx	xx	xx	6.3	6.3	11.9	21.6	21.6	14.1	15.1	15.1	10.4
	Other/Non-Infrastructure	xx	xx	xx	xx	xx	xx	1.3	1.3	0.3	-10.1	(10.1)	0.6	3.4	3.4	6.2
	Statutory/Regulatory	xx	xx	xx	xx	xx	xx	30.6	30.6	24.5	37	37.0	20.2	52.9	52.9	22.6
	System Capacity & Performance	xx	xx	xx	xx	xx	xx	9.5	9.5	10.4	10.5	10.5	17.5	8.7	8.7	4.7
	Total	40.3	40.3	37.8	57.4	57.4	44.4	59.9	59.9	62.2	81.7	81.7	67.0	97	97.0	93.1

* RAV-3 format as of fiscal year ends. FY10 is forecasted as it was in 9-mtd PSC quarterly report filed Feb 2010.

Date of Request: February 24, 2010 | Request No. AJR-3
Due Date: March 8, 2010 | NMPC Req. No. NM 80 DPS 57

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Aric Rider

TO: Infrastructure and Operations Panel

Request:

A. Provide a detailed timeline that describes the Company's annual common capital expenditures budgeting process. The flow chart/timeline of the preparation and approval process should include a description and title of the Company personnel responsible for each step, approximate dates, and relevant sign-offs.

B. Provide the electric common expenditure budgets presented to the Board of Directors for fiscal years ending 2006, 2007, 2008, 2009 and 2010.

C. Provide the common capital expenditure budgets approved by the Board of Directors for fiscal years ending 2006, 2007, 2008, 2009 and 2010, in the same format as response B, above.

D. Provide the actual common capital expenditures for fiscal years ending 2006, 2007, 2008, 2009 and 2010, in the same format as response B, above.

Response:

A. The Company has separate annual budgeting process flows for the "Property Services" and "Information Services" groups, both of which fall under the common capital expenditures umbrella. Please see AJR-3, Exhibit 1 for the Information Services process flow, the Property Services process flow is as follows:

The planning cycle starts in August for both opex and capital. The capital plan is developed by specific review of 3 main categories of spending:

a. Proposed new projects where scopes and approximate timings are known.
b. Ongoing projects with approved estimates and known spending levels.

c. Baseline Asset Long Term Projects (Preventative Maintenance and significant upgrades.

Projects are matched to overall budget guidelines for spend set by the Property Services Leadership team. Developing the spending plan is an iterative process. The Property Forum, made up of Line of Business Leaders in the U.S., reviews strategy and helps prioritize projects as well.

The Property Services capital plan is prepared by Property Services Management with Financial Services support. The capital plan is approved/sponsored by the Facilities Department VP, then submitted to the Shared Service Executive and Property Executive VP in October. The Property Services capital plan is included with the overall National Grid plc Business Plan which goes to the National Grid plc Board for approval in March each year.

B. Please see AJR-3, Exhibit 2 attached which provides the common capital expenditure budgets presented to the National Grid plc Board of Directors for fiscal years ending 2006 through 2010.

C. The National Grid plc Board of Directors approved the common capital expenditures budgets for fiscal years ending 2006 through 2010 without making any changes to the budgets presented. These are provided in AJR-3, Exhibit 2 as referenced in the response to question B above.

D. Please see AJR-3, Exhibit 2 which provides the actual common capital expenditures for fiscal years ending 2006 through 2010.

Name of Respondent:	Date of Reply:
Mark Eddy	March 8, 2010

Department	Process	Period
IS Enterprise Architecture	A review of the 3-5 year Technology Route-Map and Application Route-Map is carried out and updated	February – April
IS Enterprise Architecture	Based on the Application Route-Map and the Technology Route-Map, a 3-5 year Technical Infrastructure Blueprint is produced that feeds into the IS Investment Plan in May/July	March-July
LoB/IS Business Relationship Manager (BRM)	The Application Route-Map feeds into the Line of Business Management who, with support from the IS Business Relationship Managers (BRM) develop the LoB IS Strategy	April (delivered by May)
LoB/IS BRM	Once the LoB Strategy is developed, the LoB Managers work with the IS BRM's to develop a 3-5 year Investment Plan	May-July
IS BRM/IS Finance	There is a regular review and update of the IS project portfolio which feeds into the overall IS Investment Plan in August	January - December
IS Strategic Planning/IS Enterprise Architecture	The LoB Strategy along with the LoB Investment Plan from all LoB's are fed back to IS who collate the investment information in an overall IS Investment Plan. IS Enterprise Architecture feed into this process ensuring that the investment projects still meet the application and technology road-maps. The first draft IS Investment Plan is delivered in July	May-July
IS Strategic Planning/IS Enterprise Architecture	The Investment Plan is constantly reviewed and updated with any minor changes. The Investment Plan is approved by the IS Exec and published in the middle of September.	July-September
IS Finance	The Full five year IS Business Plan is developed. The IS Investment Plan feeds into the overall Group Business plan	August-November
IS Finance	The IS Business Plan is refined and reviewed based on opex and capex Corporate expenditure constraints.	November-December
National Grid Executive	IS Business Plan endorsed by the National Grid Exec	December
National Grid Board of Directors	The IS Approved Business Plan is consolidated in to a National Grid Business Plan that is submitted to the National Grid Board. The Board approves the budget year.	February - March

Niagara Mohawk Electric Common plant Budget vs Actual FY2006 through FY2010 ($m)

	[redacted]	FY06 Actuals	[redacted]	FY07 Actuals	[redacted]	FY08 Actuals	[redacted]	FY09 Actuals	[redacted]	FY10 Forecasted Actuals
Facilities & Other Shared Services	10.0	8.8	13.7	12.2	28.6	10.5	25.4	12.8	22.7	19.0
FY05 & FY06 Benefit capitalization adjustment				17.9						
Deferral settlement-capitalization policy change				8.9						
FY03 & FY04 Benefit capitalization adjustment						3.1				
Adjustments & Other	0.0	0.0	0.0	1.5	0.0	(0.7)	0.0	0.0	0.0	0.0
Total	10.0	8.8	13.7	40.5	28.6	12.9	25.4	12.8	22.7	19.0

Niagara Mohawk Electric Common plant Budget vs Actual FY2006 through FY2010 ($m)

	[redacted]	FY06 Actuals	[redacted]	FY07 Actuals	[redacted]	FY08 Actuals	[redacted]	FY09 Actuals	[redacted]	FY10 Forecasted Actuals
Facilities & Other Shared Services	10.0	8.8	13.7	12.2	28.6	10.5	25.4	12.8	22.7	19.0
Adjustments & Other	0.0	0.0	0.0	28.3	0.0	2.4	0.0	0.0	0.0	0.0
Total	10.0	8.8	13.7	40.5	28.6	12.9	25.4	12.8	22.7	19.0

Date of Request: February 25, 2010
Due Date: March 8, 2010

Request No. RAV-40
NMPC Req. No. NM 98 DPS 63

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirement Panel

Request:

In its 1/31/07 Narragansett Follow-on Merger Credit Compliance filing in Case 01-M-0075, the Company forecasted a phase-in of net synergy savings allocable to NMPC's electric operations as follows:

YE 8/07 -$2.332 million
YE 8/08 +$3.262 million
YE 8/09 +$4.975 million
YE 8/10 +$8.137 million
YE 8/11 +$8.285 million

In the current rate case, the historic test year is YE 9/09, which is only one month different from the YE 8/09 figures provided in the above noted compliance filing. Yet, in projecting rate year expenses, the Company did not make any adjustments to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 as it did in the aforementioned compliance filing and as it also did in this rate case for KeySpan Follow-on Merger savings.

Regarding the above, please provide the following information:

A. Is it correct that the Company's compliance filing position was that the synergy savings would not be fully realized until the fourth year after the Narragansett merger took place? If not, explain in full what the Company's position was as to when the synergy savings would be fully realized.

B. Fully explain why an adjustment was not made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 as it did in the aforementioned compliance filing. If it is the Company's position that the

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Narragansett Follow-on Merger savings were fully phased in / reflected in the historic test year actuals, please provide all documentation supporting that position (including studies + correspondence to top management on the accelerated phase-in + specific dates when each synergy saving was implemented + any other supporting documentation).

C. Fully explain and provide supporting detail as to why an adjustment was not made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 similar / identical to the adjustment the Company made in this rate case for Keyspan Follow-on Merger savings.

Response:

A. In the Company's 1/31/07 Narragansett Follow-on Merger Credit Compliance filing, the phase-in of synergy savings related to the Narragansett Merger was based on Step 2 of Attachment 10 of the Merger Joint Proposal.

B. No adjustment was made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of September 2009 since all savings had been realized. There are no additional initiatives related to the Narragansett Merger which the Company plans to implement. This is reflected in the method in which the Keyspan initiatives were developed. The Keyspan synergy savings initiatives were established based on a baseline employee level in which all Narragansett Gas synergies had been achieved. See Attachment 1, sheet 1 of 2, for a schedule which shows that the baseline number of employees assumed as the starting point for the Keyspan merger initiatives was 17,763 (after Narragansett initiatives which includes a labor reduction of 151 employees). Attachment 1, sheet 2 of 2 represents that the actual level of employees at the merger date was 17,760, demonstrating that the Narragansett initiatives had been realized. See Attachment 2 for a savings initiative plan in place at the start of the Narragansett Gas merger. This labor and non-labor synergy savings plan supports a reduction of 155.5 employees (FTE's) and is summarized in Attachment 2a.

C. The Company made an adjustment in this rate case for Keyspan Follow-on Merger savings because in the case of the Keyspan merger, there are synergy savings initiatives yet to be implemented. A similar adjustment was not made to the Narragansett Follow-on Merger savings because all savings initiatives have been realized as previously stated.

Name of Respondent:	Date of Reply:
James Molloy	March 9, 2010

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FTE Baseline at Keyspan Acquisition
Less: USBR & Narr Gas FTE Reductions

		Data			
2 - Parent Level Rev	3 - Parent Level Rev	[redacted]			
Electric Dist & Gener	CFO Dist & Generation	66			66
	Chief Oper Officer-Elec Dist	5,800			5,800
	Customer Markets	[illegible]365	77	17	2,272
	Generation			5	1,154
	SHES			5	250
Electric Dist & Generation Total				27	9,541
Gas Distribution	Chief Operating Officer-Gas			39	4,289
Gas Distribution Total				39	4,289
Group Reporting & O	Business Development NA				50
	CEO Executive			8	50
	External Affairs				70
	Gridcom				14
	Human Resources				19
	Internal Audit	33			33
	Legal & Regulation	213		8	205
	Treasury Services	71			71
Group Reporting & Other Total		527		16	511
Information Services	IS Bus Dev & Non-Regs	4			4
	IS Electric Distribution, Gen	172			172
	IS Enterprise Programme Office	14			14
	IS Finance, SS & Corporate	80			80
	IS Gas Distribution	83		14	69
	IS Management	108			108
	IS Strategy Implementation	10			10
	IS Technology Office	430		-	430
	IS Transmission	9			9
Information Services Total		910		14	896
Shared Services	Customer Financial Services	417		22	395
	Financial Services	298		10	288
	HR Services	211		8	203
	Property Services	413		3	410
	Shared Services Exec	15			15
	Supply Chain	843		12	831
Shared Services Total		2,196		55	2,141
Transmission	Construction & Services	236			236
	Network Asset Mgmt	62			62
	Network Operations	53			53
	Trans Regulation & Commercial	18			18
	Transmission Finance	15			15
	Transmission Mgmt	2			2
Transmission Total		385			385
Grand Total		17,990	77	151	17,763

Not Sure of Status.

Actual # of Employees at Keyspan Acquisition

		Data
2 - Parent Level Rev	3 - Parent Level Rev	Sum of Baseline FTEs
Electric Dist & Generation	CFO Dist & Generation	65.5
	Chief Oper Officer-Elec Dist	5800
	Customer Markets	2271.5
	Generation	1154
	SHES	250
Electric Dist & Generation Total		9541
Gas Distribution	Chief Operating Officer-Gas	4288
Gas Distribution Total		4288
Group Reporting & Other	Business Development NA	49.5
	CEO Executive	50
	External Affairs	70
	Gridcom	14
	Human Resources	19
	Internal Audit	32.5
	Legal & Regulation	205
	Treasury Services	71
Group Reporting & Other Total		511
Information Services	IS Bus Dev & Non-Regs	4
	IS Electric Distribution, Gen	172
	IS Enterprise Programme Office	14
	IS Finance, SS & Corporate	80
	IS Gas Distribution	69
	IS Management	108
	IS Strategy Implementation	10
	IS Technology Office	429.5
	IS Transmission	9
Information Services Total		895.5
Shared Services	Customer Financial Services	394.5
	Financial Services	288
	HR Services	201
	Property Services	409.5
	Shared Services Exec	15
	Supply Chain	831
Shared Services Total		2139
Transmission	Construction & Services	236
	Network Asset Mgmt	62
	Network Operations	52.5
	Trans Regulation & Commercial	17.5
	Transmission Finance	15
	Transmission Mgmt	2
Transmission Total		385
Grand Total		17759.5

Date of Request: March 10, 2010
Due Date: March 18, 2010

Request No. RAV-40 SUPP
NMPC Req. No. NM 98 DPS 63

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirement Panel

Request:

In its 1/31/07 Narragansett Follow-on Merger Credit Compliance filing in Case 01-M-0075, the Company forecasted a phase-in of net synergy savings allocable to NMPC's electric operations as follows:

YE 8/07 -$2.332 million
YE 8/08 +$3.262 million
YE 8/09 +$4.975 million
YE 8/10 +$8.137 million
YE 8/11 +$8.285 million

In the current rate case, the historic test year is YE 9/09, which is only one month different from the YE 8/09 figures provided in the above noted compliance filing. Yet, in projecting rate year expenses, the Company did not make any adjustments to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 as it did in the aforementioned compliance filing and as it also did in this rate case for KeySpan Follow-on Merger savings.

Regarding the above, please provide the following information:

A. Is it correct that the Company's compliance filing position was that the synergy savings would not be fully realized until the fourth year after the Narragansett merger took place? If not, explain in full what the Company's position was as to when the synergy savings would be fully realized.

B. Fully explain why an adjustment was not made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 as it did in the aforementioned compliance filing. If it is the Company's position that the

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Narragansett Follow-on Merger savings were fully phased in / reflected in the historic test year actuals, please provide all documentation supporting that position (including studies + correspondence to top management on the accelerated phase-in + specific dates when each synergy saving was implemented + any other supporting documentation).

C. Fully explain and provide supporting detail as to why an adjustment was not made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 similar / identical to the adjustment the Company made in this rate case for Keyspan Follow-on Merger savings.

Response: Supplement to previous response

A. The Company did not take any position in its compliance filing as to when the synergy savings would be fully realized. The impact of following the Merger Joint Proposal, Attachment 10 methodology was that the synergy savings would be phased in over four years.

B. It is the Company's position that the Narragansett Follow-on Merger savings are fully reflected in the historic test year actual costs. The Company is in the process of tying the implementation of specific Narragansett synergy initiatives to savings reflected in the historic test year. The process of tracking savings was not done as formally as the Keyspan Synergy savings using a central repository. As a result the process of documenting the savings involves collecting information from various departments responsible for implementing the savings. This will be completed by April 15, 2010 and we will supplement this response.

Name of Respondent:	Date of Reply:
James Molloy	March 16, 2010

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Date of Request: March 10, 2010
Due Date: March 18, 2010

Request No. RAV-40 SUPP 2
NMPC Req. No. NM 98 DPS 63

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirement Panel

Request: Subject: RAV-40

In its 1/31/07 Narragansett Follow-on Merger Credit Compliance filing in Case 01-M-0075, the Company forecasted a phase-in of net synergy savings allocable to NMPC's electric operations as follows:

YE 8/07 -$2.332 million
YE 8/08 +$3.262 million
YE 8/09 +$4.975 million
YE 8/10 +$8.137 million
YE 8/11 +$8.285 million

In the current rate case, the historic test year is YE 9/09, which is only one month different from the YE 8/09 figures provided in the above noted compliance filing. Yet, in projecting rate year expenses, the Company did not make any adjustments to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 as it did in the aforementioned compliance filing and as it also did in this rate case for KeySpan Follow-on Merger savings.

Regarding the above, please provide the following information:

A. Is it correct that the Company's compliance filing position was that the synergy savings would not be fully realized until the fourth year after the Narragansett merger took place? If not, explain in full what the Company's position was as to when the synergy savings would be fully realized.

B. Fully explain why an adjustment was not made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 as it did in the aforementioned compliance filing. If it is the Company's position that the Narragansett Follow-on Merger savings were fully phased in / reflected in the historic test year actuals, please provide all documentation supporting that position (including studies + correspondence to top management on the accelerated phase-in + specific dates when each synergy saving was implemented + any other supporting documentation).

C. Fully explain and provide supporting detail as to why an adjustment was not made to the historic test year to reflect the portion of Narragansett Follow-on Merger savings not fully realized as of 9/09 similar / identical to the adjustment the Company made in this rate case for Keyspan Follow-on Merger savings.

Response: Supplement to previous response

As stated in the response to RAV-40 Supplemental, the Company has compiled the attached analysis to demonstrate that the Company had completed the initiatives associated with the integration of New England Gas into National Grid prior to the test year. To support the demonstration that the Company had achieved the synergy savings associated with the integration initiatives, the Company prepared a supplemental analysis as explained below:

- First, the Company compiled a listing of 130 FTEs who had left the organization on or before June 30, 2008 (see Schedule 1 of the supplemental analysis). These FTEs were sorted by the department/sub-team that the employee worked in at the time of the acquisition. These positions are summarized by sub-team in Column (b) of the summary schedule.
- Next, the Company reviewed a list of employees still employed by National Grid but whose positions were identified as reductions in the integration savings initiatives plan in place at the acquisition. These employees were still employed by the Company at the start of the HTY, but in different capacities than at the date of acquisition. Twenty-four (24) FTE positions were identified as savings from the initial plan (see Schedule 2 of supplemental analysis). The positions are summarized by sub-team in column (c) of the summary schedule.
- The Company then took the list of 19 employees who were offered positions to remain with Southern Union's Massachusetts operation post-merger. These employees were never employed by National Grid, but their positions were identified as savings in the initial plan (see Schedule 3 of supplemental analysis). These positions are summarized in column (d) of the summary schedule.

The analysis demonstrates there were actually 173 FTE savings, column (e), a total of the three groups described above. The analysis also demonstrates that the Company has already implemented the initiatives and realized the associated savings. The savings realized would have included not only the FTE reductions themselves, but also the non-labor savings attributable to the FTE reductions. The Company does not anticipate any further Narragansett merger synergy savings in the rate years.

Schedule 4 of the Supplemental analysis is a table of the initial 155.5 FTE savings per the initial synergy savings plan. A date of completion for each sub-team reduction initiative has been added to the table.

Name of Respondent:	Date of Reply:
James Molloy	May 28, 2010

Date of Request: February 25, 2010
Due Date: March 8, 2010

Request No. RAV-41
NMPC Req. No. NM 99 DPS 64

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirement Panel

Request:

A. Regarding Exhibit RRP-2, Schedule 42, Sheet 1, in calculating the $22.214 million KeySpan synergy savings "adjustment to reflect conditions in rate year 2011," the Company appears to have subtracted from the $200 million total synergy savings and efficiency gains estimate the amount of such savings said to be realized in the historic test year. The Company then allocated 24.926% of this difference to NMPC electric operations. Finally, the Company added in 3.2146% inflation to restate the savings into rate year dollar.

1. Please indicate if the above accurately describes the Company's methodology to determine the $22.214 million adjustment. If not, fully explain, in full, why you disagree with the above description of the Company's methodology.
2.Please indicate if the Company agrees that the above methodology understates the proper rate year adjustment because the 3.2146% inflation adjustment should only be applied to bring the actual historic test year (YE 9/30/09) savings realized into rate year dollars; a higher inflation rate should have been used on the $200 million of total synergy saving and efficiency gain estimate, because the $200 million is only stated in 2007 dollars.
3.If you agree with the observation made in A.2 above, please provide a recomputation of the rate year 2011 savings; if you disagree, explain why your methodology only produces year 2011 total synergy savings of **$206.4** million (i.e., $200 million x 1.032146), whereas the total synergy savings in the KeySpan merger case in year 4 (YE 8/11) were estimated to be **$215.4** million (See 7/20/06 NG / KeySpan Joint Petition, Exhibit 2, page 1).

B. Regarding Exhibit RRP-2, Schedule 42, Sheet 3, the Company included $19.1 million of savings associated with "HR Initiatives" in determining the amount of KeySpan synergy savings realized in the historic test year. The Company then deducted this

amount, along with other realized initiative savings, from the $200 million total synergy saving and efficiency gain estimate in
determining the KeySpan synergy savings "adjustment to reflect conditions in rate year 2011."

1. Please indicate if the above accurately describes part of the Company's methodology to determine the $22.214 million adjustment. If not, explain in full why you disagree.
2. Please indicate if the Company agrees that the above methodology understates the proper rate year adjustment because the $19.1 million of savings associated with "HR Initiatives" is not included in the $200 million total synergy savings and efficiency gains estimate. In other words, isn't it correct that the Company should still realize $102.6 million of synergy savings beyond the historic test year ($200 million of total targeted savings minus $97.4 million of actual savings directly related to the $200 million of total savings)? If not, provide a spreadsheet that reconciles the total $200 million of targeted savings by component to the $97.4 million of savings achieved through the historic test year by component, using the breakdown in Workpaper 1.
3. If you agree with the observation made in B.2 above, please provide a recomputation of the rate year 2011 savings; if you disagree, also explain why the "Day N" KeySpan merger savings of $246.9 million shown on Workpaper 1 does not include the $19.1 million of savings associated with "HR Initiatives." In responding, please be sure to address whether the $246.9 million of "Day N" savings and the $200 million of total KeySpan synergy savings from the KeySpan proceeding are made up of the exact same components except that they are quantified differently.
4. Specifically indicate if these "HR Initiatives" were included in the Mercer presentation, which is the basis for the $200 million total synergy saving estimate or if they represent savings over and above the $200 million in the Mercer presentation. If they were included in the Mercer presentation, please provide specific references within that presentation.
5.a. What are the total estimated savings from the "HR Initiatives?"
b. Why wasn't an "adjustment to reflect conditions in rate year 2011" made to reflect the HR Initiative savings that were not yet realized / fully realized in the historic test year, similar to what the Company did for yet-to-be-realized KeySpan merger savings? If an adjustment is warranted, please provide the amount, with supporting documentation and calculations.

C. Regarding Exhibit RRP-2, Schedule 42, Sheet 3, in determining the amount of KeySpan synergy savings actually realized in the historic test year, the Company also included $1.9 million of unidentified savings. This amount can only be seen by reviewing the Excel spreadsheet formula for determining the $113.657 million "Final Total (Less Bad Debt)" amount shown on Exhibit RRP-2, Schedule 42, Sheet 3.

1.Fully explain what this $1.9 million of unidentified actual KeySpan savings realized in the historic test year relates to.

2.Fully explain and show how the amount was determined to be $1.9 million.
3.Fully explain why it is not included in the detailed component by component synergy savings analysis in workpaper 1.
4.Identify the specific component in workpaper 1 to which the $1.9 million adjustment relates.
5.Include supporting documentation for this adjustment (internal correspondence, etc.) that discusses the $1.9 million of savings and when exactly the savings were first realized.

D. As noted above, workpaper 1 quantifies "Day N" KeySpan merger savings to be $246.9 million. However, in reviewing the Excel spreadsheet formula used to derive this amount, it appears the Company did not include $10.749 million of Procurement savings (see cell V 463 and the formula in cell V 466). Please indicate if the Company agrees the "Day N" KeySpan merger savings should be $257.6 million to properly include Procurement savings. If not, explain in full.

E. Please provide the following information on the aforementioned $246.9 million of "Day N" KeySpan merger savings:

1. Fully explain how this amount was derived and how it differs from the $200 million synergy saving estimate the Company is using in this rate case.
2. Are there any individual synergy savings initiatives which are not included in the $200 million synergy saving estimate that are included in the $246.9 million "Day N" synergy saving estimate, and vice versa? If so, identify all such initiatives along with the related amount of savings.
3. Is it the Company's goal to realize the "N Day" level of synergy savings? Please provide all internal top management correspondence on this subject. If it is not the Company's goal to realize this level of savings, what is the purpose of including the "N Day" savings in every quarterly Synergy Savings Tracking report provided to top management, as can be seen in the Company's response to IR RAV-9?
4. Please provide the Company's most current schedule for phased in "N Day" synergy savings. Include both fiscal year and calendar year schedules.
5. Fully explain why the Company believes rates should be set on an assumed $200 million level of total synergy savings rather than the higher level of synergy savings provided in response to part E.4 above.
6. In what year dollars are the "N Day" synergy savings stated in? Include supporting documentation that identifies the year the savings are stated in. Also, please restate these savings with applicable inflation factors. Include supporting workpapers / calculations.

Response:

A.1. The process detailed in Part A. above, accurately describes the Company's methodology for determining the $22.214 million adjustment on Exhibit RRP-2, Schedule 42, Sheet 1.

A.2. The Company agrees that the methodology described in Part A. above understates the proper rate year adjustments.

A.3. Please see Attachment 1 for a recomputation of the rate year 2011 savings. The revised savings of $23.065 million will be included in the Corrections and Updates.

B.1. The Company agrees that the process in Part B. above accurately describes part of the Company's methodology to determine the $22.214 million adjustment.

B.2. The Company disagrees that methodology described in Part B. contributes to an understatement of the rate year adjustment. Please see response to Part E for a detailed explanation of the $200 million target. Workpaper 1 identifies the savings by initiative achieved to date against the nominal Day N target of $246 million. The Company does not possess a breakdown of the $200 million target by initiative. The $200 million was the total savings that National Grid committed to as part of the acquisition of Keyspan. It was recognized in the testimony provided by A.V. Feibleman and R. J. Levin of Oliver Wyman [Mercer?] (Case 06-M-0878) as an appropriate stretch goal requiring much work by the management to achieve this. In other words the Mercer presentation provided a list of initiatives to achieve the $200 million target with some cushion, as it was recognized that it would not be possible to achieve all initiatives at the 100% confidence level.

B.3. The $19.1 million of HR Initiatives was not included in the nominal target of $246 million. Please note on the list of initiatives provided in Workpaper 1 that some of the initiatives are less clearly defined than others. These present challenges and a degree of flexibility to management to achieve savings within their area of responsibility. As mentioned in Part B.2. above, the $200 million target was expected to be a stretch goal. The lines of business have been challenged throughout the post integration period to identify additional synergies as it is clear that certain Mercer initiatives will not be achieved. Although these HR initiatives were not identified at the time of the Mercer presentation, they have been subsequently identified as synergies and thus should contribute to the $200 million target. Please see response to Part E for a detailed explanation of the difference between the $246.9 million and $200 million.

B.4. These savings are not listed in the Mercer presentation and as stated in the response to Part B.3. above, it is the intention that these HR Initiatives contribute to the $200 million target.

B.5.a. The total estimated savings for the HR Initiatives is $20.9 million.

B.5.b. These initiatives have been fully achieved and no additional savings are anticipated at this time. As mentioned in the response to Part B.4., it is the intention that these initiatives will contribute to the total $200 million targeted savings and therefore no adjustment is warranted.

C.1. through C.4.

The $1.9 million relates to Gas Weather hedge savings. This amount can be seen on Workpaper 1, line 220 under Gas Distribution Initiatives. For presentation purposes, this amount is included in the Bad Debt line of the quarterly synergy reports as provided in response to Request No. DPS-13 (RAV-9). In calculating the savings attributable to the operating companies, it should therefore be included, as the bill pool allocations include this amount. Hence it has been added back to ensure that the split of synergies across the operating companies is appropriate.

C.5 The savings were first realized in the March 2009 synergy report. Please see Attachment 2 to RAV-41 for documentation of internal correspondence.

D. The "Day N" total for Keyspan Integration is correctly quantified as $246.9 million. The initiatives in Workpaper 1 listed between lines 439 and 463 inclusive, are duplicated within the initiatives listed above in the various lines of business. The reason for this is that these are procurement initiatives and both procurement and the lines of business have dual responsibility for achieving these. In order to avoid a double count, the $10.749 million in cell V463 has not been added to the formula in cell V466.

E.1. In addition to the response to Part B.2. above, the foundation of the Synergy Savings project was laid out in the Integration Transition Workshop presentation known as the Mercer Presentation. Integration initiatives were established by National Grid with the assistance of outside consultant Oliver Wyman, formerly Mercer Management Consulting. Each line of business identified a set of initiatives relevant to its operations and established project management teams and a reporting process in an effort to ensure that the initiatives are delivered and the savings realized.

In early 2006, National Grid and KeySpan began an integration planning initiative to establish how the combined company would operate in the future and to develop detailed estimates of merger savings and cost to achieve. The initiatives are described below:

The integration team was led by senior executives of both companies and reviewed all aspects of the operations of the operating companies of National Grid and KeySpan to identify areas in which greater efficiencies could be realized or where greater value could be provided to customers. The objectives of the integration teams were to make preliminary recommendations to the company leadership so they could make decisions regarding how to achieve synergy savings, develop service improvements for the combined company, and assure a seamless transition on the closing date of the Transaction. With regard to the synergy savings, the integration team completed an analysis from which it intended to formulate preliminary recommendations for the company leadership to decide how best to target specific synergy savings in each function of the business.

The integration team was led on a day-to-day basis by Mr. Kwong Nuey of National Grid and Mr. John Caroselli of KeySpan. Nine functional teams, reporting to Mr. Nuey and Mr. Caroselli, were established to design recommended approaches and processes for the future and to develop detailed estimates of potential merger savings and costs for their respective areas.

The nine teams were organized around the following functional areas:

Corporate Services;
Finance and Accounting;
Human Resources;
Information Technology;
Customer Service and Marketing;
Gas Operations;
Electric Transmission and Distribution;
Shared Services; and
Generation and Energy Supply.

Each of these functional teams was led jointly by two senior managers: one from KeySpan and one from National Grid. More than 200 National Grid and KeySpan employees were involved in the work to ensure that the planning initiative benefited from the company specific knowledge and expertise of both organizations.

The methodology used by the team was similar to the methodologies used in previous mergers, including the Niagara Mohawk and EUA mergers. In each merger, a large team of individuals from both companies assessed each company's operations, identified best practices, policies, processes and systems to adopt as a combined company, designed organization structures with post-merger staffing levels, and estimated savings and costs to achieve.

The sources of savings identified by the team fall into the following broad categories:

• Consolidation of pre-merger National Grid and KeySpan organizations into a single post-merger organization (i.e. the consolidation of functions/activities that existed on both of the legacy companies) and the elimination of redundant positions;

• Standardization and improvement of business processes and practices and adoption of best practices leading to greater efficiencies and enhanced service;

• Consolidation of information technology operations, architecture and business applications;

• Standardization and joint purchase of materials and services to enhance purchasing power and reduce costs;

• Optimization of office and operating facilities, transportation fleets, and material and supply inventory; and

• Elimination of overlapping or duplicative costs, such as outside counsel, other professional services and membership dues and fees.

The team completed its one-year effort in March 2007 and made a presentation to the National Grid-KeySpan Leadership on March 21-22, 2007. The March 21-22, 2007 presentation (the "Mercer Presentation"), consisting of more than 200 pages, provides a summary of the integration planning process and estimated savings over the 1st five years post-merger (in Chapter 1). Subsequent chapters provide additional details for each functional area, such as:

-Estimated savings and the timing of savings
-Estimated costs to achieve
-Recommended initiatives for capturing savings and operating as a combined company
-High-level organization structure and estimated staffing

The savings were given likely probabilities of achievement at high and low confidence levels. The percentages ranged from 100% probability of achieving the savings to 0% and were in increments of 25%. Therefore the $247 million is a nominal number which would assume that all the savings would be realized for all the planned initiatives. At the high confidence level this would translate to approximately $215 million of savings and the low confidence level $160 million of savings.

As with any plan, changes will occur due to external factors and internal business reasons. The overall targets have been fixed and can only be changed with the approval of the Vice President of the Line of Business concerned together with the Senior Vice-President Shared Services Finance. To date no overall targets have been adjusted.

E.2. The savings not identified within the $246.9 million are shown in Workpaper 1. Each initiative identified in the Mercer presentation will have a Day N target in column V. Where the target is blank, this means that this is an initiative identified subsequent to Mercer. Please note that these are on lines 220-238, 468-470 and 473 on Workpaper 1.

As yet there are no initiatives within the $246.9 million that are not included within the $200 million. However, it has become clear that certain projects will not achieve their intended targets. For example the $20 million of targets listed on lines 160-162 have been cancelled and no savings have been identified against them.

As a result, there is a need for the Company to identify additional initiatives to ensure that the commitment to meet the $200 million target is achieved.

E.3. As mentioned in the response to Part B.2. above, the "Day N" synergy level was a nominal amount at the 100% confidence level. The Company has been on public record and has stipulated its intention to achieve the $200 million of synergy savings following the KeySpan acquisition. Thus, the Company's goal is to achieve the $200 million of synergy savings. Please see the statement made by Steve Holliday, CEO National Grid, on page 2 in a report to the investors on 19th November 2009.

http://www.nationalgrid.com/NR/rdonlyres/92182128-450D-4DA4-8A29-421741140F64/38500/NGGTranscript20091119T0915.pdf

It is accepted that the $246.9 million target detailed in the report to senior management is of limited value as this is a nominal figure. Historically, this is how it has been reported. In addition, the amount ties back to the Mercer initiatives at the 100% confidence level and gives senior management an indication of where potential gaps may be across the lines of business.

E.4. Please see Attachment 3 to RAV-41 which shows the nominal savings targets by run rate (?) and fiscal savings to date rate. These targets were prepared with the Global ERP (?) implementation plan timeframe. However, that project has now been cancelled and a local ERP solution is to be implemented. The design phase is currently taking place and when this has been finalized the Company will be clearer about the timeframe for implementation of the associated initiatives.

E.5. Please see response to Part B.2 above.

E.6. The "Day N" savings are reported using 2007 as the base year. Please see Attachment 4 to RAV-41 for a restatement of these factors with applicable inflation factors.

Name of Respondents: Date of Reply:

James M. Molloy and Stephen Heywood March 8, 2010

Date of Request: February 25, 2010
Due Date: March 8, 2010

Request No. CVB-6
NMPC Req. No. NM 102 DPS 67

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christian Bonvin

TO: Infrastructure and Operations Panel

Request:

The following questions relate to the distribution line transformer program under system capacity and performance:
1. The distribution line transformer strategy states that heavily loaded transformers are to be systematically removed from the system over the next 15 years. When did or will the 15-year cycle begin?
2. Please provide the actual number of transformer replacements per fiscal year since the program started and the number of transformer replacements forecasted for each fiscal year of the five year budget. This information should have line items (4 in total) to report on single and three phase transformers for both overhead and underground configurations.
3. Please indicate the capital costs, cost of removal, and O&M expenses for an average 27kV single phase overhead transformer and average single phase 107KV padmount transformer replacement.

Response:

1. The 15 year cycle began in FY10 and ends in FY24. However, it should be noted that the program to replace over-loaded transformers started in FY07 with the initiation of the Reliability Enhancement Program.

2. The actual number of transformers replaced under the targeted program is detailed in Attachment 1. The figure for FY10 is a fiscal year-to-date (4/1/2009 to 03/01/2010) quantity of units actually replaced. Please also note that the Company cannot provide separate numbers for single phase vs. three phase overhead transformer replacements as it only tracks the combined number of transformer locations replaced. Lastly, transformer replacement quantities beyond FY10 are recommended annual targets to ensure the program stays on track to meet the strategy. Since the Company runs an updated report on an annual basis for over-loaded transformers and then selects from

the 'top of the list', the actual quantities by transformer type will vary from year to year.

3. Based on a discussion with Christian Bonvin, the Company is providing information for typical single phase transformer installations.

The total cost to replace an overhead transformer including all labor, material, transportation, overheads, etc. based on the multi-year average of actual costs incurred in the Overloaded Transformer Program is:

Overhead Transformer	
pu CAPITAL	$4,485
pu O&M	$230
pu REMOVAL	$485
pu TOTAL	$5,200

Notes:
- The average cost includes the replacement of ancillary distribution equipment such as the pole, cross-arms, cutouts or open wire secondary conductor that are identified on a case-by-case basis from a field inspection.
- As discussed in question 2, the Company does not track overhead transformer replacements as single or three phase installations, therefore, this is an average per unit cost with no distinction made regarding; configuration (single-phase or three phase), transformer (kVA) size, or primary/secondary voltages.

The actual cost to replace an underground/padmounted, single phase transformer based on the multi-year average of actual costs incurred in the Overloaded Transformer Program is:

Underground Transformer	
pu CAPITAL	$3,560
pu O&M	$150
pu REMOVAL	$410
pu TOTAL	$4,120

Notes:
- The average cost includes the replacement of ancillary distribution equipment such as the base or secondary connectors that are identified on a case-by case basis from a field inspection.
- This is an average per unit cost for single phase pad-mounted transformers with no distinction made regarding; transformer (kVA) size, or primary/secondary voltages.

<u>Name of Respondent:</u> — <u>Date of Reply:</u>

Brian V. Hayduk — March 7, 2010

Attachment 1: Overloaded Line Transformers Replaced/Targets by Fiscal Year:

	ACTUAL QTY REPLACED				TARGETED QTY TO REPLACE			
	FY07	FY08	FY09	FY10 (YTD)	FY11	FY12	FY13	FY14
1-phase & 3-phaseOVERHEAD	133	231	469	361	*(determined on an annual basis- see response to question 1)*			
1-phase UNDERGROUND	0	3	10	6				
3-phase UNDERGROUND	0	0	2	0				
TOTAL	133	234	481	367	639	1,278	2,109	2,679

Form 103

Date of Request: February 25, 2010
Due Date: March 8, 2010

Request No. MAS-3
NMPC Req. No. NM 105 DPS 70

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Mary Ann Sorrentino

TO: Susan F. Tierney

Request:

A. On pages 28-29 of your pre-filed direct testimony you explain the annual RDM rate adjustment calculation and indicate that each RDM group reconciliation will reflect the difference between the allowed target revenue for a given year and the applicable actual billed revenues for that group in that year. The RDM rate adjustment for each group will then reflect that group's RDM reconciliation divided by the appropriate billing determinant for that group.

1) Explain how the forecasted billing determinants for the rate years ? will be determined.

2) Will the amount calculated in the revenue reconciliation process for a prior year (the group RDM over or under collection) be subject to any carrying charges?

3) Under traditional (non-RDM) ratemaking, there is a lag in actual billed revenues equaling forecasted revenues due to meter reading and billing cycles. For example, in the first month of the rate year (January 2012), actual revenues will not be the effective rate in January multiplied by billed throughput for January, as the billed rate is pro-rated (and is therefore a blend of historic and new rates). Please explain if any adjustment will be made to actual revenues to compensate for this difference. If no adjustment is proposed, explain if the company is making a reduction to its cash working capital. If not, explain why.

Response:

1. Billing determinants used in calculating the RDM rate adjustments will be based on a forecast of the Company's kWh and kW demand for the upcoming year, and will be provided to the Commission in the Company's annual RDM filing, which will be submitted as early as possible in the first quarter of each year. A separate forecast will be developed for each Reconciliation Group based upon the same methodological approaches used in developing billing determinant forecasts

provided by the Company in this rate filing (see the testimony of Dr. Alfred Morrisey.).

2. Any over or under collection of target revenue would be subject to a carrying charges as noted on page 17, line 17, of Dr. Tierney's testimony. The Company believes the appropriate rate at which carrying charges should be determined is the pre-tax weighted average cost of capital as determined appropriate by the Commission in this case. Carrying charges would be applicable during the reconciliation period as well as during any subsequent periods when any reconciliation amounts arising from over- or under-collection are refunded or recovery.

3. As noted in Dr. Tierney's testimony, the Company will track the revenue reconciliations on a monthly basis. Further, in order to differentiate revenue billed in January 2011 (rate year 1) between revenue generated from rates in effect during 2010 and revenue generated from rates approved in this proceeding, the Company will estimate the amount of revenue associated with January 2011 usage that is billed in January 2011 through the development of allocation factors. This analysis will be based on daily cycle billing units as reported from the Company's billing system and the applicable meter read dates associated with the 20 batches billed during January 2011. Based upon the 20 batches, their December 2010 and January 2011 meter read dates, the number of customers billed in each batch, and the kW and kWh sales billed in each batch, the Company can reasonably estimate the allocation of revenue between these two months to determine percentage allocators to be applied to January 2011 billed revenue for customer, demand, and energy charges, where appropriate. (Note that in other forms of revenue reconciliation, there is a continuous reconciliation from one time period to the next. Therefore, any remaining imbalance is carried and picked up in subsequent periods. In the RDM revenue reconciliation process, the intention is to fully reconcile revenue imbalances in the next annual period, so this requires a methodology such as the one described above. The process described here is akin to the one used by the Company for its natural gas RDM process.)

Name of Respondent:	Date of Reply:
Susan F. Tierney	March 8, 2010

Form 103

Date of Request: February 25, 2010
Due Date: March 8, 2010

Request No. MAS-4
NMPC Req. No. NM 106 DPS 71

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Mary Ann Sorrentino

TO: Susan F. Tierney

Request:

A. On pages 22-24 of your pre-filed direct testimony you explain why street lighting has been included as an RDM group despite that the Company does not offer energy efficiency programs for these customers. You explain there will be a phase out of favorable pricing that has been grandfathered for certain street lighting customers.

1) How many customers are grandfathered into this favorable pricing?
2) Provide the grandfathered price, throughput, and expected price once the rate is phased out for the group of customers. Include a timeline of the anticipated phase-out.

B. You also explain that Company affiliates operate energy efficiency programs on street lighting service in other service territories, which may be offered in the Company's territory in the future.

1) Explain the programs offered by the affiliate. Include service territories in which the program is in operation.
2) Explain when you would anticipate that the programs will be offered in Grid's service territory. Provide supporting information if available.

C. Provide the rate year forecasts of annual revenues for street lighting in aggregate for the rate years; indicate what portion of the street lighting revenues are associated with fixed charges, demand charges, energy charges and non-energy related (foundation charges, arm/bracket charges, pole charges, etc) charges.

D. Provide the rate year forecast of a nnual revenues for street lighting associated with Company owned and maintained streetlights. Explain why revenues associated with Company owned and maintained streetlights should be subject to the RDM.

Response:

Form 103

A.1. There are currently fourteen customers under the P.S.C. 214 Electricity tariff's Service Classification No. 2 (Full Service Street Lighting) who are charged "pricing exception" rates for a portion of the Company-owned and Company-maintained street lighting facilities they use. These customers are

(1) Amherst Central School District No. 1
(2) Town of Amherst
(3) City of Buffalo
(4) Chautauqua Utility District
(5) Village of Kenmore
(6) Town of Tonawanda
(7) Village of Williamsville
(8) City of Syracuse DPW
(9) State of New York, Syracuse Armory (Museum of Science & Technology)
(10) City of Glens Falls
(11) City of Schenectady
(12) Village of Kinderhook
(13) City of Utica DPW
(14) Town of Queensbury.

A.2. Customers receiving "pricing exception" rates pay lower charges on certain facilities charges (circuitry, foundations, etc.). Specifically, each such customer enjoys a unique selection of special facility rates on certain of their facilities, with these rates generally cheaper than normal S.C. 2 tariff rates. For their other facilities, they pay normal S.C. tariff prices. Therefore, there is not a single grandfathered price for the whole group of fourteen customers who receive pricing exceptions. Having such pricing exceptions does not affect the per-kWh rates for energy delivery charged to these customers, which are the same as those paid by all other S.C.2 customers.

Pricing exceptions will be phased out over a two-year period from 2012 to 2013, the second and third years of the Rate Plan. For 2012, each pricing exception rate will be set at the average of (a) the 2011 rate reflecting each facility's full pricing exception and (b) the standard 2013 S.C. 2 tariff rate for that particular facility. For 2013, all facilities will be subject to the standard 2013 S.C. 2 tariff rates for that particular facility.

A summary of the phaseout of these pricing exceptions can be found on pages 202-208 of Book 4 of the Rate Case filing (Exhibit JEW-4 of the Direct Testimony of John E. Walter, Manager of Outdoor Lighting). Further detail can be found on pages 175-244 of Book 25 of the Rate Case filing (Exhibit RDCM-14, Workpapers to RDCM-7 Schedules 9 and 12, Workpaper 1, Sheets 1 to 70).

B.1. In other jurisdictions, National Grid has provided incentives for energy efficiency upgrades to municipal-owned street lighting when: 1) the municipality contributed to the systems benefits charge for the electric account(s) associated with the street lighting system being treated, 2) the energy saving street lighting measure was cost effective in accordance with avoided costs tests required by that jurisdiction, and 3) the street lighting measure did not reduce the overall light levels produced by the original street lighting luminare.

B.2. The Company is in the process of evaluating options for providing its streetlighting customers with programs that allow them to better manage their use of use in streetlighting applications. However, at this time, the Company has not developed specific plans or timetables for when it might provide such programs in the future.

C. The forecasts of annual revenue for each of the three rate years can be found in Book 23 of the Rate Case filing on the following pages of the book:

- Rate Year 2011: Exhibit RDCM-7, Schedule 1, Sheet 1 of 7
- Rate Year 2012: Exhibit RDCM-7, Schedule 7, Sheet 1 of 2
- Rate Year 2013: Exhibit RDCM-7, Schedule 10, Sheet 1 of 2

On each Sheet, the "Proposed 12-Month Total" Revenue represents the forecast revenue at proposed rates. These are:
$49,727,207.52 for 2011
$50,514,457.80 for 2012,
$51,303,453.22 for 2012.
These revenues are reported before gross receipts tax. The delivery revenue reported does not include any delivery charge adjustments, such as the System Benefit Charge.

Delivery and facility revenues are separately reported in Schedules 1, 7 and 10. Delivery revenues reflect revenues collected from per kWh rates, while facility revenues reflect revenues collected from other charges, including per-customer charges and charges for use of Company-owned and/or Company-maintained facilities such as foundations, arms/brackets, and poles. Per-customer charges are assessed only for customers in Service Classification 4 (Traffic Control), where a monthly location charge of $23.14 is applied to each bill account.

Delivery revenue decreases in 2011 because a portion of it is replaced by a Merchant Function Charge, which is not subject to the Revenue Decoupling Mechanism. The relevant forecast revenues subject to the RDM are those revenues in the Delivery Revenue and Facility Revenue columns.

D. Company-owned and Company-maintained facilities serve customers belonging to streetlighting service classifications S.C. 1 (Private Area Lighting) and S.C.2 (Full Service Street Lighting). In addition, a portion of the facilities that serve the Company's Contract Lighting customers are Company-owned and Company-maintained (the remainder are Customer-owned and Company-maintained).

The revenues forecast for S.C. 1 alone can be found at the top of each of the pages referenced above in the answer to question C: Pages 2, 31, and 50 of Book 23. The revenues forecast for S.C. 2 alone can be found on the following pages of Book 23 of the Rate Case filing: Pages 3, 32 and 51. The forecast revenue from Contract

Lighting customers serviced by Company-owned and Company-maintained facilities is $218,870.98 for 2011 through 2013.[1]

Name of Respondent: Date of Reply:

Susan F. Tierney March 7, 2009

[1] This estimate reflects revenues of $236,509.25 for 2011 to 2013 from all Contract Lighting customers, including those with customer-owned facilities (Exhibit RDCM-7, Schedule 1, Sheet 4 of 7). The portion of total Contract Lighting forecast revenues associated with Company-owned and Company-maintained facilities is based upon Exhibit RDCM-7, Schedule 5. Revenue for Company-owned and Company-maintained facilities is based on the sum of delivery and facility revenues associated with any service in which a price is listed in the "Company Owned" column for the "Present Annual Facility Price." Proposed 12-month delivery revenue for all services with "Company owned" prices is $167,700.56, while the corresponding facility revenue is $51,170.42 (after scaling up the annualized totals, which are based on September inventory, using the reconciliation factors in Schedule 5).

Date of Request: February 25, 2010
Due Date: March 8, 2010

Request No. PP/KD-6
NMPC Req. No. NM 112 DPS 77

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Patrick Piscitelli/ Kwaku Duah

TO: Dr. Roger Morin

Request:

Does Niagara Mohawk plan to issue common equity during the rate year? If so, provide an estimate of the equity issuance expenses associated with the equity issuance.

Response:

Currently, Niagara Mohawk has no plans to issue common stock during the 2011 - 2013 rate plan period.

Name of Respondent: Andrew Dinkel III

Date of Reply: March 3, 2010

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Date of Request: March 1, 2010
Due Date: March 11, 2010

Request No. CLG-2
NMPC Req. No. NM 115 DPS 80

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christopher L Graves

TO: Rate Design, Customer and Markets

Request:

Has the Company considered expanding the population of customers subject to mandatory Hourly Pricing (MHP) rates by reducing the demand threshold for Hourly Pricing in Service Classification Nos. 3?

Please provide information about customers as follows:

1. For potential MHP customers who have demand between 250 kW and 499 kW:

a. How many customers have demand between 250 kW and 499 kW?

b. What is the approximate load of the customers?

c. How many of the customers are full service customers?

d. What is the approximate load of the full service customers?

e. How many customers would qualify for an exemption from Hourly Pricing because they receive economic development rates for power?

f. How much load is represented by customers who would qualify for an exemption from Hourly Pricing?

g. How many customers would require the installation of new interval meters?

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Response:

The Company is submitting a supplemental response for CLG 2 because an error was found with the calculation of average demand which was used to classify SC3 customers within each demand group requested in CLG 1-4. The error was found when providing a response to CLG-16. Please see Attachment 1 Supp for the corrected response.

Name of Respondent:	Date of Reply:
Pamela B. Dise	June 17, 2010

SC3 Customers with Average Demand between 250kW and 499kW

	(A)	(B)	(C)	(D)
	Total Annual kWh	Bill Accounts	Exisitng Interval Meters	Interval Meters Needed
1 Retail Access	1,402,108,107	837	245	592
2 Full Service	490,970,602	342	119	223
3 Total	1,893,078,709	1,179	364	815
4 Exempt*	147,401,163	99	57	42

*Exempt = EZR and PFJ

Date of Request: March 1, 2010
Due Date: March 11, 2010

Request No. CLG-5
NMPC Req. No. NM 118 DPS 83

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christopher L Graves

TO: Rate Design, Customer and Markets

Request:

On February 27, 2009, Niagara Mohawk Power Corporation d/b/a National Grid filed "Two-Year Evaluation Report on Mandatory Hourly Pricing" in compliance with Commission Order in Case 03-E-0641. At pages 29 of the Evaluation Report, National Grid recommends: ". . . that the Commission defer any expansion of MHP program to a greater number of customers until such time as the Company can recommend an improved design for the MHP tariff with respect to capacity costs."

Is the Company prepared to make a recommendation on how capacity cost should be recovered in the MHP tariff? If yes, what are the Company's recommendations?

Response:

The Company believes two options are available for improving the recovery of capacity costs in its Mandatory Hourly Pricing (MHP) tariff. The first option is to change the spread of capacity costs to a much lower number of hours in the year based upon a peak demand threshold. This would result in much higher energy charges for certain, limited hours of the year. Customers would receive these price signals on the day prior to any day that is forecast to be above certain peak load levels. The second option is to use the "capacity tag" method which bills customers in the following year for their demand at the time of the peak demand in the present year.

The Company believes that the most appropriate means for recovering capacity costs from MHP customers is through the first option of limiting recovery of demand charges to certain high peak load hours in the year. The Company has reached this conclusion for three reasons. First, the approach maintains continuity of rate structures for the Company's current MHP customers. The Company believes that this is an important consideration because our customers have been on our MHP tariff for many years. By recovering capacity costs through energy charges in the MHP tariff, customers will be able to better comprehend and adapt to the new rates. Second, the first option will not create a need for significant modifications to the Company's current billing systems. Third, this option would allow the Commission to compare customer reaction to different pricing methods for capacity cost recovery in New York and, in its comparison, determine which method promotes greater levels of efficient energy use and peak load reduction by customers.

As explained in the response to CLG-7, the Company will be implementing a capacity cost recovery mechanism similar to the first option discussed herein as part of its Smart Grid pilot program, which will allow it to assess whether such a mechanism will produce a significantly larger load reduction from customers under hourly pricing than have been produced to date. The Company believes that it should defer making any changes to its MHP program until it has been able to conduct this assessment.

Name of Respondent:	Date of Reply:
Peter Zschokke	March 11, 2010

Date of Request: March 1, 2010
Due Date: March 11, 2010

Request No. DSM-4
NMPC Req. No. NM 123 DPS 88

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: David Morrell

TO: Revenue Requirement Panel

Request:

1. Please provide an inventory, work papers, or other form of justification for the expected increase in floor trim acres.

2. Testimony describing the 115kV widening expense makes references to danger trees being removed outside the Right-of-way (ROW) and that trees located **outside** the ROW are the source of most tree-caused outages. In other parts of your testimony the work is described as widening within the ROW limits.

   Please clarify if this work is widening work inside the ROW or Danger tree work outside the ROW.

3. Please include the inventory, work papers, or other form of justification regarding:

   a) acres of the 115kV widening or danger tree work;
   b) acres of non 115kV Danger tree work;
   c) acres of Sub T-widening work.

4. Please provide the contract specification for both Danger tree work and Widening work.

5. Why are substations in this category of O&M expenses, as they are not reported in the Company's annual Part 84 filing?

6. If this Information Request is too voluminous or time consuming, please call David Morrell to work out something regarding the data that is acceptable to both the Company and Staff.

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Response:

1. Page 223 of 266 of the Testimony of the Infrastructure and Operations Panel, lines 15 through 17, state "The historic test year costs for ROW floor trim sites are the result of a lower than average number of trim site acres." The response to Question A in NM 26 DPS-23 DSM-2 presented an average of actual floor trim site acres treated from the years 2006 through 2009. An increase in the allocation for trim sites in the years subsequent to the historic test year is needed because our estimated acres for 2011 through 2013 are higher than the historic test year, but closely reflect the average number of acres for the previous four years (2006 through 2009). Floor trim site acres are variable from year to year because of the selection of lines being treated each year. Since site conditions change, the Company performs detailed site-by-site inventories for each transmission line ROW prior to scheduled maintenance. These inventories are performed after the previous growing season ends and prior to the treatment of the ROW. For this reason, no inventories are available for planned work in 2011, 2012 and 2013. The floor trim acres provided in Attachment 1 (DSM-4_Attach 1_ Trim STC Mow Sites-CY11-CY12-CY13) are based on actual data from the previous cycle and are used as the basis for the CY11, CY12 and CY13 estimate. The final numbers of acres to be trimmed will be recorded upon completion of the individual inventories in early 2011, 2012, and 2013.

2. It is typically in the area outside the ROW that trees fail, resulting in tree caused outages. The 115 kV widening expense includes removing trees that are located outside the ROW and widening the established edge of the ROW, where property rights allow. Each 115 kV line will require a different degree of widening. The 115 kV system will be prioritized by line using tools such as recorded past outage history, Line Importance Factors, recent expenditures and danger tree maintenance cycles. Widening will not be done, and is not necessary, within the ROW limits.

3a. (Per a conversation with David Morrell on March 5, 2010, Mr. Morrell stated he would like an explanation as to how the Company determined the miles of ROW that will be widened per year.)

The 115 kV widening program is measured in miles. The degree of widening required for each line is variable and influenced by the unique characteristics of the vegetation and the line. The average cost of widening 115 kV lines ranges from $14,000 to $30,000 per mile (both sides of the ROW). The range of estimated costs per mile is largely based on two completed projects, Ticonderoga-Republic #2 and Gardenville-Homer Hill 151/152 where we performed 10 to 20 feet of widening per ROW edge. The Company estimates that it will widen between 50 and 110 miles of ROW per year, resulting in annual costs of approximately $1,500,000.

3b. The Danger Tree program is measured in miles. Danger Tree mileage is estimated utilizing the previous year's cost per mile to conduct danger tree work on

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transmission lines. In 2008, sub-transmission danger tree work cost $10,047 per mile, and transmission danger tree work cost $11,400 per mile. Therefore, our 2011 budget will allow us to remove an estimated 108 miles of sub-transmission danger tree edge and 126 miles of transmission danger tree edge.

3.c. The sub-transmission widening program is measured in miles, which has been set at 140 miles per year. Through this program, the goal is to widen all the sub-transmission lines that have exhibited poor reliability performance, are of high importance, and have high risk forested edges as determined by the Company's foresters.

4. Contractors for our vegetation management program are required by contract to provide services in accordance with our standards for vegetation management. Section 6.1.2, pages 23 - 25 of Attachment 2 (DSM-4_Attach 2_2010-2011 ROW Veg Mgt Specification), provides a description of the Company's Danger Tree Program and includes requirements for Level 6 (widening) activities. Level 6 prescribes clearing the ROW to a new width specified by the Company.

5. The substation bare ground treatment program, presented as Attachment 1 in response to Question A of NM 25 DPS-22 DSM-1, is part of the Company's transmission vegetation management budget planned for the rate years. These O&M expenses are not reported in the Company's annual Part 84 Plan filing because the Plan does not include substation work.

Name of Respondent:	Date of Reply:
Dawn Travalini	March 10, 2010

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
7716467	53	0.92	Brush Lands	8221	7716352	Cut, stump treat and chip	23
4535017	46	0.57	Residential	5210	4535940	Cut, stump treat and chip	23
7716471	55	0.17	Residential	5341	7716352	Cut, stump treat and chip	23
7716505	71	0.54	Residential	5241	7716352	Cut, stump treat and chip	23
7716522	78	0.26	Residential	5332	7716352	Cut, stump treat and chip	23
7716535	82	0.28	Residential	5222	7716352	Cut, stump treat and chip	23
4534987	16	0.22	Road Crossing	3221	4535940	Cut, stump treat and chip	23
5370074	13	1.08	Road Crossing	3311	5370650	Cut, stump treat and chip	23
5370089	28	0.70	Road Crossing	3331	5370650	Cut, stump treat and chip	23
7716357	3	2.63	Road Crossing	3243	7716352	Cut, stump treat and chip	23
7716389	19	0.46	Road Crossing	3331	7716352	Cut, stump treat and chip	23
7716441	40	1.40	Road Crossing	3231	7716352	Cut, stump treat and chip	23
7716565	97	0.14	Streams	1332	7716352	Cut, stump treat and chip	23
7716499	68	1.55	Woodlands	9241	7716352	Mechanical brush mowing	23
4535023	51	0.92	Residential	5310	4535940	Trim, prune tree	23
5370076	15	1.17	Residential	5320	5370650	Trim, prune tree	23
7716387	18	0.78	Residential	5321	7716352	Trim, prune tree	23
7716479	59	1.08	Residential	5320	7716352	Trim, prune tree	23
7716515	75	1.21	Residential	5320	7716352	Trim, prune tree	23
7716527	79	0.36	Residential	5310	7716352	Trim, prune tree	23
7716537	83	0.60	Residential	5320	7716352	Trim, prune tree	23
7716549	89	1.99	Residential	5331	7716352	Trim, prune tree	23
7716563	96	0.44	Residential	5310	7716352	Trim, prune tree	23
7716577	103	6.00	Residential	5321	7716352	Trim, prune tree	23
7716580	104	0.53	River Crossing	1311	7716352	Trim, prune tree	23
4534972	1	0.66	Road Crossing	3321	4535940	Trim, prune tree	23
4534997	26	0.35	Road Crossing	3111	4535940	Trim, prune tree	23
4535006	35	0.29	Road Crossing	3320	4535940	Trim, prune tree	23
5370075	14	0.16	Road Crossing	3310	5370650	Trim, prune tree	23
7716359	4	7.98	Road Crossing	3341	7716352	Trim, prune tree	23
7716443	41	3.59	Road Crossing	3341	7716352	Trim, prune tree	23
7716445	42	1.96	Road Crossing	3331	7716352	Trim, prune tree	23
7716603	115	0.79	Road Crossing	3211	7716352	Trim, prune tree	23
4531644	16	0.67	Brush Lands	8313	4535857	Cut, stump treat and chip	34.5
4531656	28	1.97	Brush Lands	8223	4535857	Cut, stump treat and chip	34.5

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
4532483	11	1.74	Brush Lands	8222	4535896	Cut, stump treat and chip	34.5
4532488	16	1.06	Brush Lands	8322	4535896	Cut, stump treat and chip	34.5
5308859	22	0.13	Brush Lands	8223	5323127	Cut, stump treat and chip	34.5
5308877	41	0.42	Brush Lands	8233	5323127	Cut, stump treat and chip	34.5
5308881	46	0.51	Brush Lands	8312	5323127	Cut, stump treat and chip	34.5
5309367	79	0.06	Brush Lands	8311	5323093	Cut, stump treat and chip	34.5
5309804	33	0.28	Brush Lands	8212	5323105	Cut, stump treat and chip	34.5
5309837	67	0.69	Brush Lands	8311	5323105	Cut, stump treat and chip	34.5
5310376	134	0.23	Brush Lands	8222	5323130	Cut, stump treat and chip	34.5
5310388	142	0.66	Brush Lands	8232	5323134	Cut, stump treat and chip	34.5
5310390	142	2.13	Brush Lands	8232	5323134	Cut, stump treat and chip	34.5
5310461	37	0.23	Brush Lands	8333	5323131	Cut, stump treat and chip	34.5
5310809	10	0.68	Brush Lands	8000	5323106	Cut, stump treat and chip	34.5
5369348	30	0.50	Brush Lands	8111	5370657	Cut, stump treat and chip	34.5
5369421	101	0.96	Brush Lands	8111	5370657	Cut, stump treat and chip	34.5
7444199	5	0.46	Brush Lands	8312	5323105	Cut, stump treat and chip	34.5
7444203	5	0.63	Brush Lands	8210	5323105	Cut, stump treat and chip	34.5
7444214	5	0.30	Brush Lands	8210	5323105	Cut, stump treat and chip	34.5
7444230	5	0.32	Brush Lands	8211	5323105	Cut, stump treat and chip	34.5
7444232	5	0.69	Brush Lands	8311	5323105	Cut, stump treat and chip	34.5
7444237	5	0.62	Brush Lands	8211	5323105	Cut, stump treat and chip	34.5
7444568	7	0.31	Brush Lands	8232	5323096	Cut, stump treat and chip	34.5
7463211	16	0.26	Brush Lands	8212	5323294	Cut, stump treat and chip	34.5
7463214	16	2.10	Brush Lands	8223	5323294	Cut, stump treat and chip	34.5
5310393	142	1.46	Commercial/Industi	4211	5323134	Cut, stump treat and chip	34.5
5308874	38	0.69	Field	6211	5323127	Cut, stump treat and chip	34.5
5309874	32	0.29	Field	6210	5323106	Cut, stump treat and chip	34.5
5309902	53	0.30	Field	6000	5323106	Cut, stump treat and chip	34.5
5309921	72	0.49	Field	6311	5323106	Cut, stump treat and chip	34.5
5369357	39	2.38	Field	6110	5370657	Cut, stump treat and chip	34.5
7444185	5	0.40	Field	6220	5323105	Cut, stump treat and chip	34.5
7444187	5	0.66	Field	6111	5323105	Cut, stump treat and chip	34.5
7444198	5	1.61	Field	6211	5323105	Cut, stump treat and chip	34.5
7444205	5	0.41	Field	6311	5323105	Cut, stump treat and chip	34.5
7444563	7	1.41	Field	6211	5323096	Cut, stump treat and chip	34.5

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5310463	39	0.22	Pasture	7211	5323131	Cut, stump treat and chip	34.5
7444209	5	0.53	Pasture	7210	5323105	Cut, stump treat and chip	34.5
4460954	99	0.94	Residential	5211	4462161	Cut, stump treat and chip	34.5
5308839	3	0.23	Residential	5331	5323136	Cut, stump treat and chip	34.5
5308847	10	0.18	Residential	5310	5323127	Cut, stump treat and chip	34.5
5308863	27	0.54	Residential	5310	5323127	Cut, stump treat and chip	34.5
5308875	39	0.13	Residential	5320	5323127	Cut, stump treat and chip	34.5
5309330	42	0.44	Residential	5320	5323093	Cut, stump treat and chip	34.5
5309335	47	0.57	Residential	5321	5323093	Cut, stump treat and chip	34.5
5309358	70	0.61	Residential	5320	5323093	Cut, stump treat and chip	34.5
5309681	40	1.92	Residential	5323	5323085	Cut, stump treat and chip	34.5
5309780	9	1.77	Residential	5213	5323105	Cut, stump treat and chip	34.5
5309783	13	0.61	Residential	5330	5323105	Cut, stump treat and chip	34.5
5309784	14	0.35	Residential	5310	5323105	Cut, stump treat and chip	34.5
5309786	16	0.51	Residential	5322	5323105	Cut, stump treat and chip	34.5
5309789	18	1.49	Residential	5322	5323105	Cut, stump treat and chip	34.5
5309794	23	0.38	Residential	5311	5323105	Cut, stump treat and chip	34.5
5309805	34	0.92	Residential	5310	5323105	Cut, stump treat and chip	34.5
5309812	41	0.58	Residential	5211	5323105	Cut, stump treat and chip	34.5
5309819	48	0.27	Residential	5330	5323105	Cut, stump treat and chip	34.5
5309823	52	0.01	Residential	5311	5323105	Cut, stump treat and chip	34.5
5309836	66	0.23	Residential	5322	5323105	Cut, stump treat and chip	34.5
5309843	74	0.45	Residential	5311	5323105	Cut, stump treat and chip	34.5
5309853	6	0.22	Residential	5310	5323106	Cut, stump treat and chip	34.5
5309857	15	0.70	Residential	5310	5323106	Cut, stump treat and chip	34.5
5309860	18	0.35	Residential	5321	5323106	Cut, stump treat and chip	34.5
5309899	52	1.92	Residential	5210	5323109	Cut, stump treat and chip	34.5
5309901	52	0.72	Residential	5321	5323109	Cut, stump treat and chip	34.5
5309931	82	0.74	Residential	5320	5323106	Cut, stump treat and chip	34.5
5309954	107	0.63	Residential	5311	5323106	Cut, stump treat and chip	34.5
5309970	123	1.78	Residential	5331	5323106	Cut, stump treat and chip	34.5
5310268	24	0.78	Residential	5322	5323130	Cut, stump treat and chip	34.5
5310377	135	0.22	Residential	5210	5323130	Cut, stump treat and chip	34.5
5310424	16	0.17	Residential	5000	5323138	Cut, stump treat and chip	34.5
5310432	16	7.06	Residential	5310	5323138	Cut, stump treat and chip	34.5

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5310474	47	0.63	Residential	5322	5323131	Cut, stump treat and chip	34.5
5310773	83	2.09	Residential	5310	5323093	Cut, stump treat and chip	34.5
5310808	9	0.11	Residential	5311	5323106	Cut, stump treat and chip	34.5
5310834	16	2.86	Residential	5211	5323095	Cut, stump treat and chip	34.5
5315633	64	0.20	Residential	5212	5323287	Cut, stump treat and chip	34.5
5316172	4	0.35	Residential	5111	5323332	Cut, stump treat and chip	34.5
5319378	71	0.69	Residential	5323	5323385	Cut, stump treat and chip	34.5
5319421	114	2.60	Residential	5331	5323385	Cut, stump treat and chip	34.5
5320588	20	0.60	Residential	5222	5323406	Cut, stump treat and chip	34.5
5370320	31	0.38	Residential	5321	5370707	Cut, stump treat and chip	34.5
7444188	5	0.19	Residential	5310	5323105	Cut, stump treat and chip	34.5
7444194	5	0.83	Residential	5310	5323105	Cut, stump treat and chip	34.5
7444208	5	0.20	Residential	5310	5323105	Cut, stump treat and chip	34.5
7444216	6	1.14	Residential	5310	5323105	Cut, stump treat and chip	34.5
7444218	6	1.27	Residential	5111	5323105	Cut, stump treat and chip	34.5
7445770	42	0.50	Residential	5321	5323287	Cut, stump treat and chip	34.5
7463203	12	0.43	Residential	5211	5323294	Cut, stump treat and chip	34.5
7841137	5	0.98	Residential	4320	5370653	Cut, stump treat and chip	34.5
4460869	14	0.11	Road Crossing	3320	4462161	Cut, stump treat and chip	34.5
4460918	63	0.01	Road Crossing	3000	4462161	Cut, stump treat and chip	34.5
4532484	12	0.19	Road Crossing	3310	4535896	Cut, stump treat and chip	34.5
5308867	31	0.25	Road Crossing	3321	5323127	Cut, stump treat and chip	34.5
5309295	5	0.70	Road Crossing	3211	5323093	Cut, stump treat and chip	34.5
5310737	57	0.40	Road Crossing	3311	5323127	Cut, stump treat and chip	34.5
5310842	132	0.10	Road Crossing	3000	5323130	Cut, stump treat and chip	34.5
5315631	62	0.17	Road Crossing	3310	5323287	Cut, stump treat and chip	34.5
5320737	12	3.19	Road Crossing	3223	5323407	Cut, stump treat and chip	34.5
5370314	25	0.14	Road Crossing	3211	5370707	Cut, stump treat and chip	34.5
5370336	47	0.08	Road Crossing	3321	5370707	Cut, stump treat and chip	34.5
5370359	70	0.11	Road Crossing	3211	5370707	Cut, stump treat and chip	34.5
7444197	5	0.37	Road Crossing	3001	5323105	Cut, stump treat and chip	34.5
7444419	4	0.00	Road Crossing	3001	5370634	Cut, stump treat and chip	34.5
7462987	76	0.31	Road Crossing	3310	5323406	Cut, stump treat and chip	34.5
7463213	16	1.66	Road Crossing	3111	5323294	Cut, stump treat and chip	34.5
7841138	6	0.12	Road Crossing	3320	5370653	Cut, stump treat and chip	34.5

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5309359	71	0.06	Streams	1221	5323093	Cut, stump treat and chip	34.5
5309381	95	0.36	Streams	1320	5323093	Cut, stump treat and chip	34.5
5310421	16	0.06	Streams	1312	5323138	Cut, stump treat and chip	34.5
5315938	29	0.05	Streams	1322	5323294	Cut, stump treat and chip	34.5
7444233	5	0.13	Streams	1210	5323105	Cut, stump treat and chip	34.5
5309856	14	0.29	Woodlands	9322	5323106	Cut, stump treat and chip	34.5
5309858	16	0.63	Woodlands	9311	5323106	Cut, stump treat and chip	34.5
5309904	55	0.11	Woodlands	9322	5323106	Cut, stump treat and chip	34.5
5309969	122	0.04	Woodlands	9332	5323106	Cut, stump treat and chip	34.5
5310810	11	0.59	Woodlands	9321	5323106	Cut, stump treat and chip	34.5
5316176	8	0.30	Woodlands	9323	5323332	Cut, stump treat and chip	34.5
7444211	5	0.13	Woodlands	9211	5323105	Cut, stump treat and chip	34.5
5308845	8	0.80	Brush Lands	8233	5323127	Mechanical brush mowing	34.5
5309635	129	0.99	Brush Lands	8122	5323078	Mechanical brush mowing	34.5
5309653	15	1.01	Brush Lands	8213	5323084	Mechanical brush mowing	34.5
5309782	12	0.63	Brush Lands	8321	5323105	Mechanical brush mowing	34.5
5310548	18	1.15	Brush Lands	8223	5323096	Mechanical brush mowing	34.5
5319406	99	1.61	Brush Lands	8330	5323385	Mechanical brush mowing	34.5
5319413	106	0.69	Brush Lands	8333	5323385	Mechanical brush mowing	34.5
5369323	5	3.93	Brush Lands	8232	5370657	Mechanical brush mowing	34.5
5369367	49	0.52	Brush Lands	8121	5370657	Mechanical brush mowing	34.5
5369377	59	1.21	Brush Lands	8321	5370657	Mechanical brush mowing	34.5
5369402	82	0.69	Brush Lands	8233	5370657	Mechanical brush mowing	34.5
5369412	92	0.33	Brush Lands	8222	5370657	Mechanical brush mowing	34.5
5369420	100	1.56	Brush Lands	8231	5370657	Mechanical brush mowing	34.5
7443156	171	0.00	Brush Lands	8222	5241869	Mechanical brush mowing	34.5
7443163	173	0.00	Brush Lands	8323	5241869	Mechanical brush mowing	34.5
7444140	103	1.03	Brush Lands	8221	5370657	Mechanical brush mowing	34.5
7444141	103	0.91	Brush Lands	8110	5370657	Mechanical brush mowing	34.5
7463356	170	0.00	Brush Lands	8313	5241869	Mechanical brush mowing	34.5
5369359	41	1.87	Field	6222	5370657	Mechanical brush mowing	34.5
5369410	90	1.72	Field	6341	5370657	Mechanical brush mowing	34.5
7463348	166	0.00	Pasture	7332	5241869	Mechanical brush mowing	34.5
5369397	77	0.62	Residential	5111	5370657	Mechanical brush mowing	34.5
5369414	94	0.15	Residential	5321	5370657	Mechanical brush mowing	34.5

Projected CY2011 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5369415	95	0.85	Residential	5311	5370657	Mechanical brush mowing	34.5
7443159	172	0.00	Road Crossing	3322	5241869	Mechanical brush mowing	34.5
5369360	42	0.03	Streams	1222	5370657	Mechanical brush mowing	34.5
7443164	174	0.00	Streams	1113	5241869	Mechanical brush mowing	34.5
5309659	21	0.57	Wetlands	2222	5323084	Mechanical brush mowing	34.5
5369361	43	0.45	Wetlands	2222	5370657	Mechanical brush mowing	34.5
5369363	45	0.39	Wetlands	2222	5370657	Mechanical brush mowing	34.5
5369366	48	0.76	Wetlands	2222	5370657	Mechanical brush mowing	34.5
5369368	50	0.79	Wetlands	2322	5370657	Mechanical brush mowing	34.5
5369370	52	0.34	Wetlands	2222	5370657	Mechanical brush mowing	34.5
5309654	16	1.52	Woodlands	9133	5323084	Mechanical brush mowing	34.5
5309656	18	1.27	Woodlands	9222	5323084	Mechanical brush mowing	34.5
5309658	20	0.69	Woodlands	9233	5323084	Mechanical brush mowing	34.5
5310551	19	0.89	Woodlands	9222	5323096	Mechanical brush mowing	34.5
5369362	44	0.57	Woodlands	9341	5370657	Mechanical brush mowing	34.5
5369364	46	1.76	Woodlands	9223	5370657	Mechanical brush mowing	34.5
5369365	47	5.93	Woodlands	9341	5370657	Mechanical brush mowing	34.5
5369369	51	2.01	Woodlands	9233	5370657	Mechanical brush mowing	34.5
5369371	53	1.20	Woodlands	9221	5370657	Mechanical brush mowing	34.5
5369398	78	0.37	Woodlands	9222	5370657	Mechanical brush mowing	34.5
5369407	87	0.80	Woodlands	9232	5370657	Mechanical brush mowing	34.5
5369413	93	0.83	Woodlands	9331	5370657	Mechanical brush mowing	34.5
7443165	175	0.00	Woodlands	9212	5241869	Mechanical brush mowing	34.5
7463178	115	0.00	Woodlands	9333	5323385	Mechanical brush mowing	34.5
7463180	117	0.00	Woodlands	9333	5323385	Mechanical brush mowing	34.5
4460985	129	5.48	Brush Lands	8000	4462161	Trim, prune tree	34.5
5308851	14	0.31	Brush Lands	8312	5323127	Trim, prune tree	34.5
5308855	18	0.14	Brush Lands	8311	5323127	Trim, prune tree	34.5
5315611	44	0.06	Brush Lands	8311	5323287	Trim, prune tree	34.5
5315950	40	0.37	Brush Lands	8323	5323294	Trim, prune tree	34.5
5316191	15	2.72	Brush Lands	8213	5323332	Trim, prune tree	34.5
5316192	16	0.44	Brush Lands	8332	5323332	Trim, prune tree	34.5
5316195	19	1.97	Brush Lands	8332	5323332	Trim, prune tree	34.5
5320739	14	0.30	Brush Lands	8312	5323407	Trim, prune tree	34.5
5320887	118	3.16	Brush Lands	8003	5323407	Trim, prune tree	34.5

Projected CY2011 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5369339	21	1.01	Brush Lands	8211	5370657	Trim, prune tree	34.5
5369342	24	0.13	Brush Lands	8222	5370657	Trim, prune tree	34.5
5369346	28	0.90	Brush Lands	8311	5370657	Trim, prune tree	34.5
5369425	105	0.50	Brush Lands	8322	5370657	Trim, prune tree	34.5
7444104	19	0.92	Brush Lands	8341	5323078	Trim, prune tree	34.5
7444560	7	0.36	Brush Lands	8112	5323096	Trim, prune tree	34.5
7445769	42	0.18	Brush Lands	8002	5323287	Trim, prune tree	34.5
7445778	18	0.16	Brush Lands	8212	5323406	Trim, prune tree	34.5
7445795	45	0.08	Brush Lands	8313	5323406	Trim, prune tree	34.5
7463284	20	0.04	Brush Lands	8223	5323332	Trim, prune tree	34.5
5308841	4	0.90	Commercial/Industi	4321	5323127	Trim, prune tree	34.5
5310251	7	0.24	Commercial/Industi	4210	5323130	Trim, prune tree	34.5
5369332	14	0.95	Commercial/Industi	4233	5370657	Trim, prune tree	34.5
4460910	55	1.38	Field	6221	4462161	Trim, prune tree	34.5
5309894	52	3.86	Field	6000	5323106	Trim, prune tree	34.5
5310325	81	1.36	Field	6310	5323130	Trim, prune tree	34.5
5310338	94	0.01	Field	6310	5323130	Trim, prune tree	34.5
7583230	115	0.35	Field	6321	4462161	Trim, prune tree	34.5
5319412	105	0.28	Pasture	7323	5323385	Trim, prune tree	34.5
5320828	88	0.37	Pasture	7000	5323407	Trim, prune tree	34.5
4460863	8	0.53	Residential	5321	4462161	Trim, prune tree	34.5
4460876	21	2.11	Residential	5321	4462161	Trim, prune tree	34.5
4460878	23	2.20	Residential	5321	4462161	Trim, prune tree	34.5
4460881	26	7.68	Residential	5221	4462161	Trim, prune tree	34.5
4460885	30	0.40	Residential	5311	4462161	Trim, prune tree	34.5
4460887	32	0.58	Residential	5310	4462161	Trim, prune tree	34.5
4460889	34	2.21	Residential	5320	4462161	Trim, prune tree	34.5
4460891	36	1.70	Residential	5320	4462161	Trim, prune tree	34.5
4460903	48	0.49	Residential	5312	4462161	Trim, prune tree	34.5
4460909	54	2.37	Residential	5310	4462161	Trim, prune tree	34.5
4460912	57	0.31	Residential	5212	4462161	Trim, prune tree	34.5
4460915	60	0.34	Residential	5321	4462161	Trim, prune tree	34.5
4460917	62	2.07	Residential	5112	4462161	Trim, prune tree	34.5
4460919	64	3.68	Residential	5322	4462161	Trim, prune tree	34.5
4460921	66	1.11	Residential	5321	4462161	Trim, prune tree	34.5

Projected CY2011 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
4460924	69	9.88	Residential	5321	4462161	Trim, prune tree	34.5
4460933	78	1.81	Residential	5320	4462161	Trim, prune tree	34.5
4460936	81	7.41	Residential	5331	4462161	Trim, prune tree	34.5
4460939	84	1.80	Residential	5321	4462161	Trim, prune tree	34.5
4460965	110	2.18	Residential	5321	4462161	Trim, prune tree	34.5
4460975	119	0.42	Residential	5311	4462161	Trim, prune tree	34.5
4460980	124	0.16	Residential	5310	4462161	Trim, prune tree	34.5
4460984	128	5.05	Residential	5321	4462161	Trim, prune tree	34.5
4531645	17	1.39	Residential	5310	4535857	Trim, prune tree	34.5
5240479	92	0.26	Residential	5311	5241869	Trim, prune tree	34.5
5308850	13	0.10	Residential	5311	5323127	Trim, prune tree	34.5
5308854	17	0.41	Residential	5310	5323127	Trim, prune tree	34.5
5308870	34	2.29	Residential	5311	5323127	Trim, prune tree	34.5
5308873	37	1.12	Residential	5321	5323127	Trim, prune tree	34.5
5308879	43	0.48	Residential	5320	5323127	Trim, prune tree	34.5
5308883	48	1.40	Residential	5320	5323127	Trim, prune tree	34.5
5308887	54	0.93	Residential	5310	5323127	Trim, prune tree	34.5
5309319	29	0.81	Residential	5311	5323093	Trim, prune tree	34.5
5309327	39	0.38	Residential	5320	5323093	Trim, prune tree	34.5
5309341	52	0.94	Residential	5210	5323101	Trim, prune tree	34.5
5309368	80	1.22	Residential	5310	5323093	Trim, prune tree	34.5
5309379	93	0.43	Residential	5320	5323093	Trim, prune tree	34.5
5309383	97	0.33	Residential	5311	5323093	Trim, prune tree	34.5
5309447	3	0.69	Residential	5312	5323142	Trim, prune tree	34.5
5309611	106	0.25	Residential	5310	5323078	Trim, prune tree	34.5
5309613	108	0.43	Residential	5223	5323078	Trim, prune tree	34.5
5309626	120	0.34	Residential	5321	5323078	Trim, prune tree	34.5
5309663	25	3.11	Residential	5311	5323084	Trim, prune tree	34.5
5309674	36	0.69	Residential	5322	5323084	Trim, prune tree	34.5
5309683	40	0.83	Residential	5311	5323085	Trim, prune tree	34.5
5309697	52	0.40	Residential	5311	5323084	Trim, prune tree	34.5
5309712	4	3.06	Residential	5310	5323105	Trim, prune tree	34.5
5309797	26	0.84	Residential	5310	5323105	Trim, prune tree	34.5
5309798	27	1.58	Residential	5310	5323105	Trim, prune tree	34.5
5309801	30	2.29	Residential	5310	5323105	Trim, prune tree	34.5

Projected CY2011 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5309803	32	0.28	Residential	5310	5323105	Trim, prune tree	34.5
5309822	51	2.32	Residential	5311	5323105	Trim, prune tree	34.5
5309829	59	0.41	Residential	5311	5323105	Trim, prune tree	34.5
5309841	71	0.83	Residential	5310	5323105	Trim, prune tree	34.5
5309862	20	1.49	Residential	5310	5323106	Trim, prune tree	34.5
5309863	21	1.06	Residential	5310	5323106	Trim, prune tree	34.5
5309866	24	0.15	Residential	5310	5323106	Trim, prune tree	34.5
5309868	26	0.36	Residential	5310	5323106	Trim, prune tree	34.5
5309870	28	0.23	Residential	5310	5323106	Trim, prune tree	34.5
5309888	47	0.13	Residential	5310	5323106	Trim, prune tree	34.5
5309890	49	0.27	Residential	5000	5323106	Trim, prune tree	34.5
5309895	52	0.08	Residential	5110	5323109	Trim, prune tree	34.5
5309924	75	1.20	Residential	5310	5323106	Trim, prune tree	34.5
5309929	80	0.70	Residential	5311	5323106	Trim, prune tree	34.5
5309949	100	0.37	Residential	5000	5323106	Trim, prune tree	34.5
5309961	114	0.33	Residential	5310	5323106	Trim, prune tree	34.5
5310241	21	2.29	Residential	5233	5323095	Trim, prune tree	34.5
5310253	9	0.32	Residential	5310	5323130	Trim, prune tree	34.5
5310266	22	1.13	Residential	5321	5323130	Trim, prune tree	34.5
5310321	77	4.22	Residential	5311	5323130	Trim, prune tree	34.5
5310339	96	0.10	Residential	5310	5323130	Trim, prune tree	34.5
5310345	102	0.38	Residential	5310	5323130	Trim, prune tree	34.5
5310357	114	0.07	Residential	5310	5323130	Trim, prune tree	34.5
5310361	118	0.43	Residential	5310	5323130	Trim, prune tree	34.5
5310371	128	0.34	Residential	5322	5323130	Trim, prune tree	34.5
5310375	133	0.10	Residential	5310	5323130	Trim, prune tree	34.5
5310380	138	0.87	Residential	5310	5323130	Trim, prune tree	34.5
5310384	142	4.11	Residential	5333	5323130	Trim, prune tree	34.5
5310415	16	0.23	Residential	5310	5323138	Trim, prune tree	34.5
5310427	16	1.09	Residential	5321	5323138	Trim, prune tree	34.5
5310430	16	1.60	Residential	5320	5323138	Trim, prune tree	34.5
5310488	1	0.57	Residential	5311	5323096	Trim, prune tree	34.5
5310490	3	0.38	Residential	5333	5323096	Trim, prune tree	34.5
5310537	10	0.43	Residential	5310	5323096	Trim, prune tree	34.5
5310554	22	2.00	Residential	5321	5323096	Trim, prune tree	34.5

Projected CY2011 Floor Trim Acres

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5310731	2	7.54	Residential	5321	5323127	Trim, prune tree	34.5
5310733	45	0.73	Residential	5321	5323127	Trim, prune tree	34.5
5310734	50	1.04	Residential	5310	5323127	Trim, prune tree	34.5
5310772	53	6.49	Residential	5310	5323093	Trim, prune tree	34.5
5310791	29	0.25	Residential	5321	5323078	Trim, prune tree	34.5
5310793	31	1.00	Residential	5311	5323078	Trim, prune tree	34.5
5310811	12	2.86	Residential	5331	5323106	Trim, prune tree	34.5
5310835	18	3.97	Residential	5322	5323095	Trim, prune tree	34.5
5310836	23	3.44	Residential	5232	5323095	Trim, prune tree	34.5
5310837	24	3.38	Residential	5310	5323099	Trim, prune tree	34.5
5310839	60	1.21	Residential	5310	5323130	Trim, prune tree	34.5
5315565	9	0.56	Residential	5331	5323287	Trim, prune tree	34.5
5315568	12	0.42	Residential	5321	5323287	Trim, prune tree	34.5
5315585	29	1.49	Residential	5322	5323287	Trim, prune tree	34.5
5315627	58	1.68	Residential	5320	5323287	Trim, prune tree	34.5
5315629	60	0.36	Residential	5320	5323287	Trim, prune tree	34.5
5315634	65	0.58	Residential	5311	5323287	Trim, prune tree	34.5
5315918	17	0.43	Residential	5310	5323294	Trim, prune tree	34.5
5315933	24	0.05	Residential	5310	5323294	Trim, prune tree	34.5
5315934	25	2.43	Residential	5311	5323294	Trim, prune tree	34.5
5315935	26	1.91	Residential	5320	5323294	Trim, prune tree	34.5
5315937	28	0.75	Residential	5331	5323294	Trim, prune tree	34.5
5315939	30	2.06	Residential	5321	5323294	Trim, prune tree	34.5
5315940	31	0.63	Residential	5331	5323294	Trim, prune tree	34.5
5315941	32	0.86	Residential	5310	5323294	Trim, prune tree	34.5
5315943	34	0.21	Residential	5330	5323294	Trim, prune tree	34.5
5315945	36	0.84	Residential	5321	5323294	Trim, prune tree	34.5
5315948	38	0.54	Residential	5323	5323294	Trim, prune tree	34.5
5316175	7	0.81	Residential	5321	5323332	Trim, prune tree	34.5
5316189	13	0.60	Residential	5122	5323332	Trim, prune tree	34.5
5319217	18	2.26	Residential	5211	5323384	Trim, prune tree	34.5
5319286	87	0.70	Residential	5313	5323384	Trim, prune tree	34.5
5319373	66	0.59	Residential	5320	5323385	Trim, prune tree	34.5
5319393	86	0.17	Residential	5322	5323385	Trim, prune tree	34.5
5319411	104	0.41	Residential	5310	5323385	Trim, prune tree	34.5

Projected CY2011 Floor Trim Acres

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5320587	19	0.10	Residential	5000	5323406	Trim, prune tree	34.5
5320589	21	0.44	Residential	5310	5323406	Trim, prune tree	34.5
5320600	32	2.45	Residential	5310	5323406	Trim, prune tree	34.5
5320601	33	0.14	Residential	5312	5323406	Trim, prune tree	34.5
5320657	54	0.30	Residential	5331	5323406	Trim, prune tree	34.5
5320668	65	1.24	Residential	5111	5323406	Trim, prune tree	34.5
5320676	73	0.80	Residential	5310	5323406	Trim, prune tree	34.5
5320733	8	0.06	Residential	5320	5323407	Trim, prune tree	34.5
5320738	13	0.70	Residential	5311	5323407	Trim, prune tree	34.5
5320741	16	2.10	Residential	5311	5323407	Trim, prune tree	34.5
5320742	17	0.60	Residential	5310	5323407	Trim, prune tree	34.5
5320787	48	0.14	Residential	5311	5323407	Trim, prune tree	34.5
5320795	56	1.00	Residential	5310	5323407	Trim, prune tree	34.5
5320883	114	0.10	Residential	5310	5323407	Trim, prune tree	34.5
5320886	117	0.07	Residential	5310	5323407	Trim, prune tree	34.5
5320889	119	0.10	Residential	5301	5323407	Trim, prune tree	34.5
5369186	47	1.57	Residential	5310	5370686	Trim, prune tree	34.5
5369338	20	0.64	Residential	5311	5370657	Trim, prune tree	34.5
5369340	22	0.57	Residential	5311	5370657	Trim, prune tree	34.5
5369393	73	3.23	Residential	5310	5370657	Trim, prune tree	34.5
5369404	84	0.17	Residential	5322	5370657	Trim, prune tree	34.5
5369417	97	5.38	Residential	5310	5370657	Trim, prune tree	34.5
5369418	98	3.87	Residential	5330	5370657	Trim, prune tree	34.5
5369419	99	1.17	Residential	5321	5370657	Trim, prune tree	34.5
5369422	102	0.88	Residential	5231	5370657	Trim, prune tree	34.5
5369424	104	0.77	Residential	5322	5370657	Trim, prune tree	34.5
5369438	9	0.46	Residential	5321	5370634	Trim, prune tree	34.5
7442949	70	0.00	Residential	5331	5370686	Trim, prune tree	34.5
7443191	73	0.00	Residential	5320	5370686	Trim, prune tree	34.5
7444092	19	0.63	Residential	5222	5323078	Trim, prune tree	34.5
7444178	5	0.10	Residential	5310	5323105	Trim, prune tree	34.5
7444180	5	2.89	Residential	5311	5323105	Trim, prune tree	34.5
7444182	5	0.24	Residential	5320	5323105	Trim, prune tree	34.5
7444184	5	1.57	Residential	5310	5323105	Trim, prune tree	34.5
7444190	5	0.33	Residential	5310	5323105	Trim, prune tree	34.5

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7444202	5	0.32	Residential	5310	5323105	Trim, prune tree	34.5
7444207	5	0.18	Residential	5310	5323105	Trim, prune tree	34.5
7444234	5	0.52	Residential	5311	5323105	Trim, prune tree	34.5
7444238	6	0.76	Residential	5310	5323105	Trim, prune tree	34.5
7444417	2	0.00	Residential	5321	5370634	Trim, prune tree	34.5
7444422	7	0.00	Residential	5321	5370634	Trim, prune tree	34.5
7444537	7	0.25	Residential	5310	5323096	Trim, prune tree	34.5
7444559	7	0.32	Residential	5001	5323096	Trim, prune tree	34.5
7444561	7	1.25	Residential	5311	5323096	Trim, prune tree	34.5
7444564	7	0.61	Residential	5310	5323096	Trim, prune tree	34.5
7444566	7	0.10	Residential	5310	5323096	Trim, prune tree	34.5
7444569	7	0.72	Residential	5210	5323096	Trim, prune tree	34.5
7445639	96	0.00	Residential	5322	5323384	Trim, prune tree	34.5
7445776	82	2.05	Residential	5320	5323287	Trim, prune tree	34.5
7445784	45	0.28	Residential	5310	5323406	Trim, prune tree	34.5
7463013	126	0.00	Residential	5311	5323407	Trim, prune tree	34.5
7463209	16	0.97	Residential	5332	5323294	Trim, prune tree	34.5
7463210	16	0.82	Residential	5310	5323294	Trim, prune tree	34.5
7463218	20	0.26	Residential	5320	5323294	Trim, prune tree	34.5
4460871	16	2.59	Road Crossing	3310	4462161	Trim, prune tree	34.5
4460902	47	0.22	Road Crossing	3341	4462161	Trim, prune tree	34.5
4460911	56	0.16	Road Crossing	3321	4462161	Trim, prune tree	34.5
4460948	93	0.80	Road Crossing	3310	4462161	Trim, prune tree	34.5
4460974	118	5.04	Road Crossing	3310	4462161	Trim, prune tree	34.5
5309785	15	0.77	Road Crossing	3310	5323105	Trim, prune tree	34.5
5309909	60	0.29	Road Crossing	3000	5323106	Trim, prune tree	34.5
5309917	68	0.23	Road Crossing	3210	5323106	Trim, prune tree	34.5
5310269	25	0.21	Road Crossing	3311	5323130	Trim, prune tree	34.5
5310318	74	1.47	Road Crossing	3310	5323130	Trim, prune tree	34.5
5319208	9	0.20	Road Crossing	3000	5323384	Trim, prune tree	34.5
5319235	36	1.79	Road Crossing	3311	5323384	Trim, prune tree	34.5
5320570	6	0.14	Road Crossing	3320	5323406	Trim, prune tree	34.5
5320616	40	0.40	Road Crossing	3311	5323406	Trim, prune tree	34.5
5320651	48	0.16	Road Crossing	3312	5323406	Trim, prune tree	34.5
5320706	95	0.30	Road Crossing	3311	5323406	Trim, prune tree	34.5

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5320720	109	0.40	Road Crossing	3310	5323406	Trim, prune tree	34.5
5320727	2	1.10	Road Crossing	3311	5323407	Trim, prune tree	34.5
5320754	29	0.14	Road Crossing	3312	5323407	Trim, prune tree	34.5
5369326	8	0.81	Road Crossing	3310	5370657	Trim, prune tree	34.5
5369334	16	0.07	Road Crossing	3312	5370657	Trim, prune tree	34.5
5369337	19	0.34	Road Crossing	3221	5370657	Trim, prune tree	34.5
5369347	29	0.22	Road Crossing	3320	5370657	Trim, prune tree	34.5
5369373	55	0.08	Road Crossing	3310	5370657	Trim, prune tree	34.5
5369387	69	1.04	Road Crossing	3310	5370657	Trim, prune tree	34.5
5369403	83	0.55	Road Crossing	3310	5370657	Trim, prune tree	34.5
5369405	85	3.43	Road Crossing	3311	5370657	Trim, prune tree	34.5
5369406	86	0.15	Road Crossing	3321	5370657	Trim, prune tree	34.5
5369416	96	10.47	Road Crossing	3222	5370657	Trim, prune tree	34.5
7442934	58	0.00	Road Crossing	3311	5370686	Trim, prune tree	34.5
7442939	69	0.00	Road Crossing	3321	5370686	Trim, prune tree	34.5
7442947	67	0.00	Road Crossing	3321	5370686	Trim, prune tree	34.5
7444095	19	0.89	Road Crossing	3210	5323078	Trim, prune tree	34.5
7444137	103	0.71	Road Crossing	3310	5370657	Trim, prune tree	34.5
7444186	5	0.11	Road Crossing	3310	5323105	Trim, prune tree	34.5
7444536	7	0.18	Road Crossing	3310	5323096	Trim, prune tree	34.5
7445640	97	0.00	Road Crossing	3311	5323384	Trim, prune tree	34.5
7445649	106	0.00	Road Crossing	3311	5323384	Trim, prune tree	34.5
7463281	9	0.10	Road Crossing	3310	5323332	Trim, prune tree	34.5
5320740	15	0.40	Streams	1312	5323407	Trim, prune tree	34.5
5309340	52	0.41	Wetlands	2312	5323093	Trim, prune tree	34.5
5309490	46	0.22	Woodlands	9320	5323142	Trim, prune tree	34.5
5309679	40	0.27	Woodlands	9333	5323084	Trim, prune tree	34.5
5320590	22	1.27	Woodlands	9323	5323406	Trim, prune tree	34.5
5369426	106	0.49	Woodlands	9320	5370657	Trim, prune tree	34.5
7444099	19	0.23	Woodlands	9112	5323078	Trim, prune tree	34.5
5232324	37	3.22	Woodlands	9213	5241806	Cut, stump treat and chip	46
5231853	1	0.53	Residential	5311	5241788	Mechanical brush mowing	46
5237853	23	9.43	Residential	5232	5241866	Mechanical brush mowing	46
5237854	24	1.40	Residential	5120	5241866	Mechanical brush mowing	46
5237850	20	0.86	Road Crossing	3323	5241866	Mechanical brush mowing	46

Projected CY2011 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5237851	21	0.16	Road Crossing	3232	5241866	Mechanical brush mowing	46
5237849	19	0.42	Streams	1030	5241866	Mechanical brush mowing	46
5237865	35	0.34	Streams	1223	5241866	Mechanical brush mowing	46
5237855	25	1.84	Woodlands	9123	5241866	Mechanical brush mowing	46
5237859	29	3.38	Woodlands	9123	5241866	Mechanical brush mowing	46
5237860	30	0.52	Woodlands	9122	5241866	Mechanical brush mowing	46
5237862	32	1.66	Woodlands	9222	5241866	Mechanical brush mowing	46
5237864	34	0.78	Woodlands	9232	5241866	Mechanical brush mowing	46
5237866	36	3.49	Woodlands	9221	5241866	Mechanical brush mowing	46
5232295	14	0.57	Brush Lands	8312	5241806	Trim, prune tree	46
5232356	61	0.24	Brush Lands	8312	5241806	Trim, prune tree	46
5232465	145	0.40	Brush Lands	8010	5241806	Trim, prune tree	46
5369051	22	2.99	Brush Lands	8141	5370679	Trim, prune tree	46
5369052	23	0.16	Brush Lands	8120	5370679	Trim, prune tree	46
5369053	24	0.94	Brush Lands	8341	5370679	Trim, prune tree	46
5232458	139	0.44	Commercial/Industı	4000	5241806	Trim, prune tree	46
5237721	19	0.15	Commercial/Industı	4131	5241862	Trim, prune tree	46
5237834	5	0.77	Commercial/Industı	4000	5241866	Trim, prune tree	46
5240467	25	0.61	Commercial/Industı	4310	5241864	Trim, prune tree	46
5231860	8	4.58	Residential	5311	5241788	Trim, prune tree	46
5232299	17	0.37	Residential	5121	5241806	Trim, prune tree	46
5232301	19	0.44	Residential	5110	5241806	Trim, prune tree	46
5232314	28	0.43	Residential	5211	5241806	Trim, prune tree	46
5232340	49	0.57	Residential	5111	5241806	Trim, prune tree	46
5232343	51	0.30	Residential	5212	5241806	Trim, prune tree	46
5232348	55	0.43	Residential	5232	5241806	Trim, prune tree	46
5232438	124	0.56	Residential	5310	5241806	Trim, prune tree	46
5232460	141	0.57	Residential	5000	5241806	Trim, prune tree	46
5232467	146	0.55	Residential	5312	5241806	Trim, prune tree	46
5232471	149	0.03	Residential	5211	5241806	Trim, prune tree	46
5237787	20	0.67	Residential	5310	5241864	Trim, prune tree	46
5237790	23	0.58	Residential	5232	5241864	Trim, prune tree	46
5237792	28	0.30	Residential	5310	5241864	Trim, prune tree	46
5237795	31	0.29	Residential	5311	5241864	Trim, prune tree	46
5237796	32	0.77	Residential	5321	5241864	Trim, prune tree	46

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5237836	7	0.67	Residential	5000	5241866	Trim, prune tree	46
5237847	17	0.60	Residential	5232	5241866	Trim, prune tree	46
5237848	18	1.34	Residential	5232	5241866	Trim, prune tree	46
5237852	22	0.23	Residential	5221	5241866	Trim, prune tree	46
5231854	2	1.52	Road Crossing	3001	5241788	Trim, prune tree	46
5232280	2	5.58	Road Crossing	3312	5241806	Trim, prune tree	46
5232291	11	4.05	Road Crossing	3210	5241806	Trim, prune tree	46
5232292	12	0.44	Road Crossing	3310	5241806	Trim, prune tree	46
5232294	13	0.85	Road Crossing	3110	5241806	Trim, prune tree	46
5232296	15	0.31	Road Crossing	3210	5241806	Trim, prune tree	46
5232298	16	2.40	Road Crossing	3211	5241806	Trim, prune tree	46
5232300	18	4.22	Road Crossing	3211	5241806	Trim, prune tree	46
5232302	20	3.62	Road Crossing	3211	5241806	Trim, prune tree	46
5232304	22	1.30	Road Crossing	3210	5241806	Trim, prune tree	46
5232306	23	0.70	Road Crossing	3212	5241806	Trim, prune tree	46
5232307	24	0.63	Road Crossing	3110	5241806	Trim, prune tree	46
5232309	25	0.31	Road Crossing	3212	5241806	Trim, prune tree	46
5232311	26	0.89	Road Crossing	3312	5241806	Trim, prune tree	46
5232312	27	3.46	Road Crossing	3211	5241806	Trim, prune tree	46
5232315	29	1.11	Road Crossing	3211	5241806	Trim, prune tree	46
5232316	30	0.68	Road Crossing	3110	5241806	Trim, prune tree	46
5232317	31	0.76	Road Crossing	3312	5241806	Trim, prune tree	46
5232320	33	0.11	Road Crossing	3212	5241806	Trim, prune tree	46
5232321	34	1.04	Road Crossing	3212	5241806	Trim, prune tree	46
5232322	35	0.14	Road Crossing	3010	5241806	Trim, prune tree	46
5232323	36	1.41	Road Crossing	3211	5241806	Trim, prune tree	46
5232325	38	0.10	Road Crossing	3312	5241806	Trim, prune tree	46
5232327	39	0.60	Road Crossing	3000	5241806	Trim, prune tree	46
5232328	40	0.65	Road Crossing	3222	5241806	Trim, prune tree	46
5232329	41	0.09	Road Crossing	3000	5241806	Trim, prune tree	46
5232331	42	0.68	Road Crossing	3322	5241806	Trim, prune tree	46
5232333	44	0.71	Road Crossing	3223	5241806	Trim, prune tree	46
5232334	45	0.03	Road Crossing	3223	5241806	Trim, prune tree	46
5232336	46	0.30	Road Crossing	3321	5241806	Trim, prune tree	46
5232337	47	0.37	Road Crossing	3211	5241806	Trim, prune tree	46

Projected CY2011 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5232338	48	0.35	Road Crossing	3000	5241806	Trim, prune tree	46
5232346	53	0.16	Road Crossing	3000	5241806	Trim, prune tree	46
5232347	54	1.89	Road Crossing	3221	5241806	Trim, prune tree	46
5232349	56	0.72	Road Crossing	3311	5241806	Trim, prune tree	46
5232350	57	0.99	Road Crossing	3000	5241806	Trim, prune tree	46
5232352	58	0.37	Road Crossing	3212	5241806	Trim, prune tree	46
5232353	59	0.64	Road Crossing	3310	5241806	Trim, prune tree	46
5232355	60	1.88	Road Crossing	3212	5241806	Trim, prune tree	46
5232358	62	1.95	Road Crossing	3212	5241806	Trim, prune tree	46
5232359	63	3.48	Road Crossing	3001	5241806	Trim, prune tree	46
5232365	69	0.69	Road Crossing	3000	5241806	Trim, prune tree	46
5232386	85	7.13	Road Crossing	3321	5241806	Trim, prune tree	46
5232387	86	0.63	Road Crossing	3110	5241806	Trim, prune tree	46
5232389	88	0.21	Road Crossing	3111	5241806	Trim, prune tree	46
5232392	90	1.34	Road Crossing	3111	5241806	Trim, prune tree	46
5232394	91	0.14	Road Crossing	3311	5241806	Trim, prune tree	46
5232400	97	1.85	Road Crossing	3232	5241806	Trim, prune tree	46
5232402	98	3.03	Road Crossing	3221	5241806	Trim, prune tree	46
5232405	100	0.65	Road Crossing	3321	5241806	Trim, prune tree	46
5232409	103	2.28	Road Crossing	3211	5241806	Trim, prune tree	46
5232410	104	3.99	Road Crossing	3211	5241806	Trim, prune tree	46
5232413	106	1.01	Road Crossing	3211	5241806	Trim, prune tree	46
5232439	125	2.07	Road Crossing	3322	5241806	Trim, prune tree	46
5232441	126	1.86	Road Crossing	3321	5241806	Trim, prune tree	46
5232450	132	0.32	Road Crossing	3112	5241806	Trim, prune tree	46
5232451	133	0.29	Road Crossing	3000	5241806	Trim, prune tree	46
5232452	134	0.44	Road Crossing	3112	5241806	Trim, prune tree	46
5232454	135	1.23	Road Crossing	3000	5241806	Trim, prune tree	46
5232456	137	0.30	Road Crossing	3211	5241806	Trim, prune tree	46
5232462	143	0.56	Road Crossing	3011	5241806	Trim, prune tree	46
5232470	148	0.57	Road Crossing	3312	5241806	Trim, prune tree	46
5237647	9	0.73	Road Crossing	3311	5241860	Trim, prune tree	46
5237789	22	1.15	Road Crossing	3313	5241864	Trim, prune tree	46
5237846	17	0.67	Road Crossing	3312	5241866	Trim, prune tree	46
5240469	27	0.14	Road Crossing	3331	5241864	Trim, prune tree	46

Projected CY2011 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5369048	19	0.69	Road Crossing	3310	5370679	Trim, prune tree	46
5369050	21	1.17	Road Crossing	3000	5370679	Trim, prune tree	46
7445538	109	1.85	Road Crossing	3211	5241806	Trim, prune tree	46
5232464	144	0.68	Streams	1212	5241806	Trim, prune tree	46
5369049	20	0.26	Streams	1003	5370679	Trim, prune tree	46
5232289	10	2.77	Woodlands	9002	5241806	Trim, prune tree	46
5232303	21	0.84	Woodlands	9211	5241806	Trim, prune tree	46
5232344	52	0.54	Woodlands	9212	5241806	Trim, prune tree	46
5232412	105	0.82	Woodlands	9221	5241806	Trim, prune tree	46
5232416	108	0.87	Woodlands	9111	5241806	Trim, prune tree	46
5232418	110	5.23	Woodlands	9211	5241806	Trim, prune tree	46
5232457	138	1.06	Woodlands	9212	5241806	Trim, prune tree	46
5232459	140	0.81	Woodlands	9212	5241806	Trim, prune tree	46
5232461	142	0.96	Woodlands	9111	5241806	Trim, prune tree	46
5237845	16	3.33	Woodlands	9222	5241866	Trim, prune tree	46
5308628	102	0.70	Residential	5310	5323091	Cut, stump treat and chip	69
5308678	149	0.52	Residential	5210	5323091	Cut, stump treat and chip	69
4533629	49	0.17	Road Crossing	3121	4535954	Cut, stump treat and chip	69
4533647	62	1.46	Road Crossing	3311	4535954	Cut, stump treat and chip	69
4533659	74	1.24	Road Crossing	3332	4535954	Cut, stump treat and chip	69
5308685	156	0.63	Field	6000	5323091	Trim, prune tree	69
4533666	89	0.59	Residential	5331	4535917	Trim, prune tree	69
5308652	125	0.46	Residential	5111	5323091	Trim, prune tree	69
5308654	127	1.67	Residential	5000	5323091	Trim, prune tree	69
4533671	96	2.19	Road Crossing	3322	4535917	Trim, prune tree	69
5308664	135	1.81	Road Crossing	3000	5323091	Trim, prune tree	69
5240520	42	0.30	Brush Lands	8322	5241908	Cut, stump treat and chip	115
7444838	21	0.00	Brush Lands	8311	5323345	Cut, stump treat and chip	115
5317742	8	0.00	Brush Lands	8233	5323345	Cut, stump treat and chip	115
5317738	4	0.11	Brush Lands	8111	5323345	Cut, stump treat and chip	115
4530831	125	4.49	Brush Lands	8331	4535836	Cut, stump treat and chip	115
5369003	307	0.83	Residential	5323	5370678	Cut, stump treat and chip	115
5369005	309	1.12	Residential	5311	5370678	Cut, stump treat and chip	115
4459249	25	0.23	Residential	5311	4462151	Cut, stump treat and chip	115
5369004	308	0.22	Residential	5223	5370678	Cut, stump treat and chip	115

Projected CY2011 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
7444945	247	0.00	Residential	5111	5323345	Cut, stump treat and chip	115
4459243	19	0.73	Residential	5211	4462151	Cut, stump treat and chip	115
5239414	88	0.79	Residential	5221	5241908	Cut, stump treat and chip	115
4459245	21	1.47	Residential	5321	4462151	Cut, stump treat and chip	115
7464021	98	0.00	Residential	5211	5323179	Cut, stump treat and chip	115
5239367	43	0.61	Residential	5310	5241908	Cut, stump treat and chip	115
4459247	23	1.20	Residential	5211	4462151	Cut, stump treat and chip	115
5237072	92	1.19	Road Crossing	3331	5241841	Cut, stump treat and chip	115
5370399	299	0.68	Road Crossing	3221	5370708	Cut, stump treat and chip	115
5239365	40	0.28	Road Crossing	3211	5241908	Cut, stump treat and chip	115
5237106	124	0.89	Road Crossing	3320	5241841	Cut, stump treat and chip	115
4530751	45	1.83	Road Crossing	3331	4535836	Cut, stump treat and chip	115
7465122	120	0.00	Road Crossing	3311	4535920	Cut, stump treat and chip	115
5370388	288	0.29	Road Crossing	3312	5370708	Cut, stump treat and chip	115
4459246	22	0.50	Streams	1211	4462151	Cut, stump treat and chip	115
7444912	203	0.00	Brush Lands	8111	5323345	Mechanical brush mowing	115
5318062	203	0.53	Brush Lands	8111	5323345	Mechanical brush mowing	115
4530837	131	0.18	Residential	5341	4535836	Mechanical brush mowing	115
4530809	103	0.71	Road Crossing	3231	4535836	Mechanical brush mowing	115
7444913	203	0.00	Wetlands	2003	5323345	Mechanical brush mowing	115
5317744	10	2.12	Brush Lands	8001	5323345	Trim, prune tree	115
5313242	59	1.97	Brush Lands	8223	5323185	Trim, prune tree	115
5233100	100	0.52	Brush Lands	8311	5241756	Trim, prune tree	115
5318068	209	7.36	Brush Lands	8310	5323345	Trim, prune tree	115
4459276	50	0.30	Brush Lands	8112	4462151	Trim, prune tree	115
5320340	136	1.09	Brush Lands	8233	5323419	Trim, prune tree	115
7444869	66	0.00	Brush Lands	8313	5323345	Trim, prune tree	115
4459288	62	0.28	Brush Lands	8223	4462151	Trim, prune tree	115
5317818	43	0.39	Brush Lands	8222	5323345	Trim, prune tree	115
4530834	128	4.27	Brush Lands	8232	4535836	Trim, prune tree	115
5320338	134	1.58	Brush Lands	8232	5323419	Trim, prune tree	115
4459284	58	0.58	Commercial/Industi	4112	4462151	Trim, prune tree	115
5369027	331	0.93	Commercial/Industi	4310	5370678	Trim, prune tree	115
5320341	137	7.47	Field	6000	5323419	Trim, prune tree	115
4534016	161	1.90	Pasture	7321	4535920	Trim, prune tree	115

Projected CY2011 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
4530207	13	0.92	Residential	5310	4535837	Trim, prune tree	115
7465125	120	0.00	Residential	5320	4535920	Trim, prune tree	115
5368431	8	0.48	Residential	5321	5370668	Trim, prune tree	115
4530836	130	4.71	Residential	5310	4535836	Trim, prune tree	115
5240904	19	0.57	Residential	5310	5241834	Trim, prune tree	115
5317923	99	0.42	Residential	5211	5323345	Trim, prune tree	115
7443673	201	0.00	Residential	5311	4535837	Trim, prune tree	115
4530750	44	1.18	Residential	5320	4535836	Trim, prune tree	115
5233036	36	0.26	Residential	5311	5241756	Trim, prune tree	115
4530833	127	1.44	Residential	5330	4535836	Trim, prune tree	115
7444944	247	0.00	Residential	5311	5323345	Trim, prune tree	115
5317787	29	2.56	Residential	5311	5323345	Trim, prune tree	115
5317783	25	0.06	Residential	5311	5323345	Trim, prune tree	115
5239440	117	0.57	Residential	5320	5241908	Trim, prune tree	115
5317959	131	1.10	Residential	5212	5323345	Trim, prune tree	115
5320339	135	2.75	Residential	5211	5323419	Trim, prune tree	115
7443017	136	0.00	Residential	5331	4535836	Trim, prune tree	115
5317780	22	0.05	Residential	5310	5323345	Trim, prune tree	115
7465134	163	0.00	Residential	5332	4535920	Trim, prune tree	115
5239538	217	1.58	Residential	5310	5241908	Trim, prune tree	115
5318073	214	0.99	Residential	5310	5323345	Trim, prune tree	115
7465059	32	0.00	Residential	5311	4535955	Trim, prune tree	115
5239396	70	0.84	Residential	5310	5241908	Trim, prune tree	115
4459292	66	1.15	Residential	5311	4462151	Trim, prune tree	115
5239413	87	1.70	Residential	5310	5241908	Trim, prune tree	115
5318060	201	0.29	Residential	5320	5323345	Trim, prune tree	115
5320354	150	1.26	Residential	5310	5323419	Trim, prune tree	115
7464022	98	0.00	Residential	5321	5323179	Trim, prune tree	115
4459248	24	0.56	Road Crossing	3000	4462151	Trim, prune tree	115
7464008	98	0.00	Road Crossing	3310	5323179	Trim, prune tree	115
5318018	188	0.08	Road Crossing	3311	5323345	Trim, prune tree	115
7444824	21	0.00	Road Crossing	3310	5323345	Trim, prune tree	115
5233027	27	0.83	Road Crossing	3003	5241756	Trim, prune tree	115
4533956	102	1.00	Road Crossing	3320	4535920	Trim, prune tree	115
7443016	135	0.00	Road Crossing	3342	4535836	Trim, prune tree	115

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5240910	25	0.69	Road Crossing	3220	5241834	Trim, prune tree	115
4530745	39	2.72	Road Crossing	3312	4535836	Trim, prune tree	115
7464019	106	0.00	Road Crossing	3333	5323179	Trim, prune tree	115
4530832	126	0.46	Road Crossing	3320	4535836	Trim, prune tree	115
5368426	3	2.07	Road Crossing	3321	5370668	Trim, prune tree	115
4530801	95	0.72	Road Crossing	3342	4535836	Trim, prune tree	115
5307377	12	7.65	Road Crossing	3330	5323083	Trim, prune tree	115
7444835	21	0.00	Road Crossing	3310	5323345	Trim, prune tree	115
5233059	59	1.60	Road Crossing	3212	5241756	Trim, prune tree	115
7444827	21	0.00	Road Crossing	3310	5323345	Trim, prune tree	115
4530292	97	4.60	Road Crossing	3310	4535837	Trim, prune tree	115
5239368	46	2.12	Road Crossing	3311	5241908	Trim, prune tree	115
5233092	92	1.01	Streams	1000	5241756	Trim, prune tree	115
4530835	129	0.27	Streams	1310	4535836	Trim, prune tree	115
4553999	38	22.61	Streams	1311	4555119	Cut, stump treat and chip	230
7442749	128	0.00	Road Crossing	3310	4555119	Trim, prune tree	230
4554057	100	0.19	Residential	5310	4555119	Trim, prune tree	230
4554003	42	5.70	Streams	1211	4555119	Cut, stump treat and chip	230
4554060	103	4.48	Road Crossing	3210	4555119	Trim, prune tree	230
4554049	92	8.60	Residential	5311	4555119	Trim, prune tree	230
4554011	52	1.60	Brush Lands	8333	4555119	Trim, prune tree	230
4553969	8	0.38	Commercial/Industi	4310	4555119	Trim, prune tree	230
4554061	104	8.40	Residential	5211	4555119	Trim, prune tree	230
4554008	47	1.10	Residential	5321	4555119	Cut, stump treat and chip	230
4554030	73	0.92	Brush Lands	8311	4555119	Trim, prune tree	230
4554053	96	2.31	Residential	5310	4555119	Trim, prune tree	230
4554012	53	1.71	Road Crossing	3310	4555119	Trim, prune tree	230
4554001	40	13.00	Residential	5311	4555119	Trim, prune tree	230
4553997	36	0.10	Residential	5311	4555119	Trim, prune tree	230
4554059	102	0.92	Residential	5000	4555119	Trim, prune tree	230
4554062	105	5.00	Streams	1211	4555119	Cut, stump treat and chip	230
4554051	94	3.68	Residential	5210	4555119	Cut, stump treat and chip	230
4554055	98	1.02	Residential	5310	4555119	Trim, prune tree	230
4555062	54	0.40	Road Crossing	3310	4555119	Trim, prune tree	230
4554006	45	4.06	Road Crossing	3311	4555119	Cut, stump treat and chip	230

Projected CY2011 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2011.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
4554029	72	6.75	Brush Lands	8000	4555119	Mechanical brush mowing	230
4554010	50	0.20	Brush Lands	8233	4555119	Trim, prune tree	230
5312030	1	1.34	Road Crossing	3312	5323271	Trim, prune tree	345
5312055	26	0.58	Road Crossing	3310	5323271	Trim, prune tree	345
	Total:	**813.34**	**acres**				

Projected CY2012 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2012.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
7463625	85	1.32	Brush Lands	8222	5241914	Cut, stump treat and chip	23
5369131	35	0.30	Commercial/In(	4321	5370685	Cut, stump treat and chip	23
5239909	91	0.06	Residential	5211	5241914	Cut, stump treat and chip	23
5369121	25	0.41	Residential	5320	5370685	Cut, stump treat and chip	23
5369133	37	0.26	Residential	5321	5370685	Cut, stump treat and chip	23
5239870	56	0.06	Road Crossing	3112	5241914	Cut, stump treat and chip	23
5239875	62	1.02	Road Crossing	3212	5241914	Cut, stump treat and chip	23
7463626	85	0.37	Road Crossing	3000	5241914	Cut, stump treat and chip	23
5238914	10	0.66	Brush Lands	8213	5241890	Mechanical brush mowing	23
5238916	12	0.30	Brush Lands	8223	5241890	Mechanical brush mowing	23
5240502	6	0.60	Woodlands	9233	5241890	Mechanical brush mowing	23
5238957	50	0.01	Brush Lands	8311	5241890	Trim, prune tree	23
5239844	30	0.50	Cropland	6000	5241914	Trim, prune tree	23
5239120	1	0.11	Residential	5310	5241895	Trim, prune tree	23
5239817	2	1.25	Residential	5310	5241914	Trim, prune tree	23
5239834	20	0.20	Residential	5310	5241914	Trim, prune tree	23
5239854	40	0.63	Residential	5311	5241914	Trim, prune tree	23
5239864	50	0.05	Residential	5311	5241914	Trim, prune tree	23
5239871	57	0.19	Residential	5310	5241914	Trim, prune tree	23
5239876	63	0.89	Residential	5321	5241914	Trim, prune tree	23
5239877	65	0.53	Residential	5231	5241914	Trim, prune tree	23
5239907	89	0.16	Residential	5312	5241914	Trim, prune tree	23
5240545	64	1.73	Residential	5311	5241914	Trim, prune tree	23
5369099	3	1.22	Residential	5320	5370685	Trim, prune tree	23
5369129	33	0.51	Residential	5001	5370685	Trim, prune tree	23
7463624	85	2.31	Residential	5311	5241914	Trim, prune tree	23
5369098	2	0.37	Road Crossing	3310	5370685	Trim, prune tree	23
7443486	97	0.26	Road Crossing	3111	5241914	Trim, prune tree	23
4460240	36	1.15	Brush Lands	8211	4462155	Cut, stump treat and chip	34.5
4461719	23	0.91	Brush Lands	8321	4462167	Cut, stump treat and chip	34.5
4531396	30	2.76	Brush Lands	9111	4535855	Cut, stump treat and chip	34.5
5308976	71	0.36	Brush Lands	8221	5323114	Cut, stump treat and chip	34.5
5309028	124	0.29	Brush Lands	8321	5323114	Cut, stump treat and chip	34.5
5309044	142	1.74	Brush Lands	8333	5323114	Cut, stump treat and chip	34.5
5309046	144	0.40	Brush Lands	8332	5323114	Cut, stump treat and chip	34.5

Projected CY2012 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2012.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	Voltage
5309094	42	0.80	Brush Lands	8222	5323115	Cut, stump treat and chip	34.5
5309135	85	1.10	Brush Lands	8221	5323115	Cut, stump treat and chip	34.5
5309217	37	2.51	Brush Lands	8232	5323117	Cut, stump treat and chip	34.5
5315162	5	2.04	Brush Lands	8322	5323177	Cut, stump treat and chip	34.5
5315675	12	1.07	Brush Lands	8323	5323289	Cut, stump treat and chip	34.5
5315693	21	0.29	Brush Lands	8311	5323289	Cut, stump treat and chip	34.5
5315706	34	0.05	Brush Lands	8313	5323289	Cut, stump treat and chip	34.5
5315959	6	0.46	Brush Lands	8213	5323295	Cut, stump treat and chip	34.5
5316032	67	1.21	Brush Lands	8212	5323295	Cut, stump treat and chip	34.5
5316047	81	0.60	Brush Lands	8313	5323295	Cut, stump treat and chip	34.5
5316049	83	1.34	Brush Lands	8230	5323295	Cut, stump treat and chip	34.5
5321776	11	1.03	Brush Lands	8331	5323454	Cut, stump treat and chip	34.5
5321812	43	0.20	Brush Lands	8312	5323454	Cut, stump treat and chip	34.5
5368576	38	1.21	Brush Lands	8332	5370674	Cut, stump treat and chip	34.5
5368711	6	0.55	Brush Lands	8311	5370676	Cut, stump treat and chip	34.5
7444432	47	0.25	Brush Lands	8311	4462166	Cut, stump treat and chip	34.5
7444463	29	0.17	Brush Lands	8311	4462167	Cut, stump treat and chip	34.5
7463230	61	0.04	Brush Lands	8323	5323295	Cut, stump treat and chip	34.5
7841030	15	0.14	Brush Lands	8340	4535869	Cut, stump treat and chip	34.5
7841038	24	0.17	Brush Lands	8241	4535869	Cut, stump treat and chip	34.5
4461582	52	0.20	Commercial/Inc	4000	4462166	Cut, stump treat and chip	34.5
5309059	7	2.77	Commercial/Inc	4310	5323115	Cut, stump treat and chip	34.5
5309192	14	2.76	Commercial/Inc	4310	5323117	Cut, stump treat and chip	34.5
5310099	67	0.61	Commercial/Inc	4220	5323118	Cut, stump treat and chip	34.5
5315656	7	0.34	Commercial/Inc	4110	5323305	Cut, stump treat and chip	34.5
5315705	33	0.56	Commercial/Inc	4312	5323289	Cut, stump treat and chip	34.5
5321804	35	0.01	Commercial/Inc	4310	5323454	Cut, stump treat and chip	34.5
7444576	8	0.10	Commercial/Inc	4321	4555137	Cut, stump treat and chip	34.5
5309085	33	0.42	Field	6110	5323115	Cut, stump treat and chip	34.5
5310093	61	11.20	Field	6111	5323118	Cut, stump treat and chip	34.5
5368955	97	2.56	Field	6111	5370677	Cut, stump treat and chip	34.5
7444429	47	1.38	Field	6310	4462166	Cut, stump treat and chip	34.5
7443856	82	0.42	Pasture	7321	4462155	Cut, stump treat and chip	34.5
7443951	24	1.10	Pasture	7310	4462166	Cut, stump treat and chip	34.5
4460275	71	0.06	Residential	5210	4462155	Cut, stump treat and chip	34.5

Projected CY2012 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2012.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
4460633	75	0.63	Residential	5312	4462158	Cut, stump treat and chip	34.5
4461246	7	0.45	Residential	5221	4462164	Cut, stump treat and chip	34.5
4461301	10	1.01	Residential	5211	4462165	Cut, stump treat and chip	34.5
4461354	62	0.06	Residential	5310	4462165	Cut, stump treat and chip	34.5
4461426	92	0.53	Residential	5000	4462165	Cut, stump treat and chip	34.5
4461718	22	0.50	Residential	5341	4462167	Cut, stump treat and chip	34.5
4531395	29	2.17	Residential	5211	4535855	Cut, stump treat and chip	34.5
4531397	31	1.50	Residential	5211	4535855	Cut, stump treat and chip	34.5
5308908	1	1.49	Residential	5322	5323114	Cut, stump treat and chip	34.5
5308914	8	0.17	Residential	5331	5323114	Cut, stump treat and chip	34.5
5308921	15	1.19	Residential	5341	5323114	Cut, stump treat and chip	34.5
5308933	27	0.42	Residential	5331	5323114	Cut, stump treat and chip	34.5
5308966	61	0.93	Residential	5311	5323114	Cut, stump treat and chip	34.5
5308975	70	0.22	Residential	5221	5323114	Cut, stump treat and chip	34.5
5309015	111	0.41	Residential	5221	5323114	Cut, stump treat and chip	34.5
5309019	115	1.53	Residential	5321	5323114	Cut, stump treat and chip	34.5
5309029	125	3.87	Residential	5331	5323114	Cut, stump treat and chip	34.5
5309053	1	0.65	Residential	5331	5323115	Cut, stump treat and chip	34.5
5309054	2	1.74	Residential	5330	5323115	Cut, stump treat and chip	34.5
5309081	29	0.75	Residential	5320	5323115	Cut, stump treat and chip	34.5
5309090	38	0.86	Residential	5331	5323115	Cut, stump treat and chip	34.5
5309108	57	0.19	Residential	5323	5323115	Cut, stump treat and chip	34.5
5309113	62	0.40	Residential	5331	5323115	Cut, stump treat and chip	34.5
5309125	74	5.64	Residential	5332	5323115	Cut, stump treat and chip	34.5
5309127	76	0.16	Residential	5311	5323115	Cut, stump treat and chip	34.5
5309214	34	0.32	Residential	5312	5323117	Cut, stump treat and chip	34.5
5309226	47	0.65	Residential	5322	5323117	Cut, stump treat and chip	34.5
5309228	49	0.31	Residential	5321	5323117	Cut, stump treat and chip	34.5
5310038	3	0.57	Residential	5322	5323118	Cut, stump treat and chip	34.5
5310091	59	1.70	Residential	5211	5323118	Cut, stump treat and chip	34.5
5310111	78	0.82	Residential	5321	5323118	Cut, stump treat and chip	34.5
5310141	107	0.33	Residential	5310	5323118	Cut, stump treat and chip	34.5
5310157	118	3.82	Residential	5221	5323118	Cut, stump treat and chip	34.5
5310167	129	2.15	Residential	5211	5323118	Cut, stump treat and chip	34.5
5310173	135	0.83	Residential	5311	5323118	Cut, stump treat and chip	34.5

Projected CY2012 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5310200	162	0.26	Residential	5213	5323118	Cut, stump treat and chip	34.5
5310816	3	0.23	Residential	5331	5323128	Cut, stump treat and chip	34.5
5313743	16	1.53	Residential	5222	5323212	Cut, stump treat and chip	34.5
5313753	25	0.34	Residential	5211	5323212	Cut, stump treat and chip	34.5
5314537	15	3.63	Residential	5220	5323245	Cut, stump treat and chip	34.5
5315694	22	0.26	Residential	5311	5323289	Cut, stump treat and chip	34.5
5315709	37	0.66	Residential	5310	5323289	Cut, stump treat and chip	34.5
5315710	38	1.95	Residential	5333	5323289	Cut, stump treat and chip	34.5
5315961	8	0.24	Residential	5311	5323295	Cut, stump treat and chip	34.5
5315963	10	1.35	Residential	5331	5323295	Cut, stump treat and chip	34.5
5316008	55	1.81	Residential	5341	5323295	Cut, stump treat and chip	34.5
5316041	75	0.17	Residential	5220	5323295	Cut, stump treat and chip	34.5
5321771	6	1.21	Residential	5330	5323454	Cut, stump treat and chip	34.5
5368642	104	0.06	Residential	5332	5370674	Cut, stump treat and chip	34.5
7463227	61	0.17	Residential	5320	5323295	Cut, stump treat and chip	34.5
7463232	61	0.25	Residential	5321	5323295	Cut, stump treat and chip	34.5
7465295	84	0.61	Residential	5231	4535909	Cut, stump treat and chip	34.5
7465304	93	0.86	Residential	5222	4535909	Cut, stump treat and chip	34.5
7716746	18	1.19	Residential	5221	4535855	Cut, stump treat and chip	34.5
7840855	11	0.75	Residential	5000	5370688	Cut, stump treat and chip	34.5
7841052	65	0.74	Residential	5322	4535869	Cut, stump treat and chip	34.5
4460242	38	5.64	Road Crossing	3221	4462155	Cut, stump treat and chip	34.5
4461265	26	0.06	Road Crossing	3331	4462164	Cut, stump treat and chip	34.5
4461331	40	1.37	Road Crossing	3000	4462165	Cut, stump treat and chip	34.5
4461717	21	0.12	Road Crossing	3321	4462167	Cut, stump treat and chip	34.5
4530936	27	0.26	Road Crossing	3221	4535869	Cut, stump treat and chip	34.5
4530963	56	0.22	Road Crossing	3223	4535869	Cut, stump treat and chip	34.5
4530980	72	0.22	Road Crossing	3231	4535869	Cut, stump treat and chip	34.5
4531375	7	0.99	Road Crossing	3231	4535855	Cut, stump treat and chip	34.5
4531377	9	1.06	Road Crossing	3221	4535855	Cut, stump treat and chip	34.5
4531394	28	1.29	Road Crossing	3223	4535855	Cut, stump treat and chip	34.5
4531398	32	0.28	Road Crossing	3221	4535855	Cut, stump treat and chip	34.5
4531405	39	0.27	Road Crossing	3231	4535855	Cut, stump treat and chip	34.5
4531407	41	0.51	Road Crossing	3210	4535855	Cut, stump treat and chip	34.5
4532510	6	1.11	Road Crossing	3212	4535909	Cut, stump treat and chip	34.5

Projected CY2012 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
4532528	24	0.57	Road Crossing	3232	4535909	Cut, stump treat and chip	34.5
4532561	57	2.99	Road Crossing	3231	4535909	Cut, stump treat and chip	34.5
4532583	79	0.19	Road Crossing	3232	4535909	Cut, stump treat and chip	34.5
4532619	100	0.60	Road Crossing	3210	4535904	Cut, stump treat and chip	34.5
5308917	11	0.16	Road Crossing	3221	5323114	Cut, stump treat and chip	34.5
5309045	143	0.12	Road Crossing	3000	5323114	Cut, stump treat and chip	34.5
5309107	56	0.23	Road Crossing	3320	5323115	Cut, stump treat and chip	34.5
5309230	51	1.33	Road Crossing	3321	5323117	Cut, stump treat and chip	34.5
5310743	38	0.08	Road Crossing	3132	5323114	Cut, stump treat and chip	34.5
5313770	42	0.27	Road Crossing	3211	5323212	Cut, stump treat and chip	34.5
5313823	91	0.46	Road Crossing	3223	5323212	Cut, stump treat and chip	34.5
5314455	44	0.84	Road Crossing	3311	5323206	Cut, stump treat and chip	34.5
5315668	5	1.58	Road Crossing	3312	5323289	Cut, stump treat and chip	34.5
5315670	7	0.21	Road Crossing	3310	5323289	Cut, stump treat and chip	34.5
5315673	10	0.02	Road Crossing	3320	5323289	Cut, stump treat and chip	34.5
5315682	15	3.01	Road Crossing	3310	5323307	Cut, stump treat and chip	34.5
5315683	16	0.02	Road Crossing	3110	5323307	Cut, stump treat and chip	34.5
5315960	7	0.21	Road Crossing	3310	5323295	Cut, stump treat and chip	34.5
5315980	27	0.36	Road Crossing	3223	5323295	Cut, stump treat and chip	34.5
5319688	21	0.57	Road Crossing	3310	5323411	Cut, stump treat and chip	34.5
5319697	30	0.12	Road Crossing	3311	5323411	Cut, stump treat and chip	34.5
5321783	18	0.16	Road Crossing	3210	5323454	Cut, stump treat and chip	34.5
5321785	20	0.27	Road Crossing	3311	5323454	Cut, stump treat and chip	34.5
5368841	7	0.12	Road Crossing	3320	5370677	Cut, stump treat and chip	34.5
7443954	24	0.13	Road Crossing	3121	4462166	Cut, stump treat and chip	34.5
7840856	6	0.15	Road Crossing	3221	5370688	Cut, stump treat and chip	34.5
7841040	31	0.27	Road Crossing	3221	4535869	Cut, stump treat and chip	34.5
4461425	91	1.93	Streams	1122	4462165	Cut, stump treat and chip	34.5
5310092	60	0.28	Streams	1222	5323118	Cut, stump treat and chip	34.5
7565271	80	0.16	Streams	1223	4462165	Cut, stump treat and chip	34.5
5308915	9	0.08	Wetlands	2332	5323114	Cut, stump treat and chip	34.5
5309093	41	1.58	Wetlands	2212	5323115	Cut, stump treat and chip	34.5
5315995	42	0.41	Woodlands	9233	5323295	Cut, stump treat and chip	34.5
5316007	54	0.51	Woodlands	5332	5323295	Cut, stump treat and chip	34.5
5368623	85	0.57	Brush Lands	8131	5370674	Mechanical brush mowing	34.5

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5368626	88	0.16	Brush Lands	8111	5370674	Mechanical brush mowing	34.5
5368708	3	0.98	Brush Lands	8342	5370676	Mechanical brush mowing	34.5
7443770	30	0.50	Brush Lands	8222	4462156	Mechanical brush mowing	34.5
4460259	55	1.97	Pasture	7342	4462155	Mechanical brush mowing	34.5
4461614	83	0.12	Pasture	7312	4462166	Mechanical brush mowing	34.5
7443758	28	0.25	Residential	5212	4462156	Mechanical brush mowing	34.5
4532207	28	1.66	Woodlands	9223	4535887	Mechanical brush mowing	34.5
4532212	22	6.23	Woodlands	9232	4535887	Mechanical brush mowing	34.5
4532219	16	1.32	Woodlands	9223	4535887	Mechanical brush mowing	34.5
5368836	2	0.59	Woodlands	9222	5370677	Mechanical brush mowing	34.5
7443771	29	2.29	Woodlands	9131	4462156	Mechanical brush mowing	34.5
4460362	63	1.06	Brush Lands	8213	4462156	Trim, prune tree	34.5
4460367	68	0.14	Brush Lands	8321	4462156	Trim, prune tree	34.5
4460598	41	1.31	Brush Lands	8312	4462158	Trim, prune tree	34.5
4461291	48	0.57	Brush Lands	8311	4462164	Trim, prune tree	34.5
4461457	123	0.75	Brush Lands	8241	4462165	Trim, prune tree	34.5
4461677	146	0.45	Brush Lands	8340	4462166	Trim, prune tree	34.5
5237230	41	0.69	Brush Lands	8332	5241855	Trim, prune tree	34.5
5309037	134	0.87	Brush Lands	8223	5323114	Trim, prune tree	34.5
5309058	6	0.67	Brush Lands	8212	5323115	Trim, prune tree	34.5
5309116	65	0.57	Brush Lands	8322	5323115	Trim, prune tree	34.5
5309202	21	0.75	Brush Lands	8223	5323117	Trim, prune tree	34.5
5315681	15	0.51	Brush Lands	8310	5323307	Trim, prune tree	34.5
5315689	18	0.79	Brush Lands	8321	5323289	Trim, prune tree	34.5
5316043	77	0.26	Brush Lands	8333	5323295	Trim, prune tree	34.5
5316045	79	0.26	Brush Lands	8323	5323295	Trim, prune tree	34.5
5368618	80	1.22	Brush Lands	8331	5370674	Trim, prune tree	34.5
5368718	13	0.32	Brush Lands	8312	5370676	Trim, prune tree	34.5
5368904	45	0.12	Brush Lands	8323	5370677	Trim, prune tree	34.5
5368918	59	0.06	Brush Lands	8321	5370677	Trim, prune tree	34.5
5368926	67	0.09	Brush Lands	8323	5370677	Trim, prune tree	34.5
5368928	69	2.97	Brush Lands	8322	5370677	Trim, prune tree	34.5
7443256	22	0.79	Brush Lands	8213	5370677	Trim, prune tree	34.5
7443284	22	0.89	Brush Lands	8222	5370677	Trim, prune tree	34.5
7443568	22	0.72	Brush Lands	8312	5370677	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	Voltage
7443921	139	0.49	Brush Lands	8111	5370674	Trim, prune tree	34.5
7443925	142	1.12	Brush Lands	8122	5370674	Trim, prune tree	34.5
7443927	141	0.06	Brush Lands	8321	5370674	Trim, prune tree	34.5
7443932	23	1.02	Brush Lands	8312	4462166	Trim, prune tree	34.5
7443961	24	0.10	Brush Lands	8110	4462166	Trim, prune tree	34.5
7444308	83	0.16	Brush Lands	8311	4462165	Trim, prune tree	34.5
7444443	47	0.11	Brush Lands	8110	4462166	Trim, prune tree	34.5
7463246	88	0.04	Brush Lands	4340	5323295	Trim, prune tree	34.5
4461245	6	1.31	Commercial/Inc	4311	4462164	Trim, prune tree	34.5
4461368	76	0.85	Commercial/Inc	4111	4462165	Trim, prune tree	34.5
4553954	8	0.67	Commercial/Inc	4310	4555137	Trim, prune tree	34.5
4553961	14	0.95	Commercial/Inc	4310	4555137	Trim, prune tree	34.5
5310060	28	0.25	Commercial/Inc	4310	5323118	Trim, prune tree	34.5
5310062	30	0.56	Commercial/Inc	4320	5323118	Trim, prune tree	34.5
5310169	131	0.15	Commercial/Inc	4310	5323118	Trim, prune tree	34.5
5315680	15	0.66	Commercial/Inc	4310	5323307	Trim, prune tree	34.5
5315691	19	0.21	Commercial/Inc	4000	5323308	Trim, prune tree	34.5
5315695	23	0.66	Commercial/Inc	4311	5323289	Trim, prune tree	34.5
5368547	9	0.11	Commercial/Inc	4311	5370674	Trim, prune tree	34.5
7443283	22	0.91	Commercial/Inc	4311	5370677	Trim, prune tree	34.5
7444445	47	2.04	Commercial/Inc	4310	4462166	Trim, prune tree	34.5
7444449	4	0.31	Commercial/Inc	4310	4462167	Trim, prune tree	34.5
7463484	18	0.00	Commercial/Inc	4310	5323341	Trim, prune tree	34.5
7565270	80	0.12	Commercial/Inc	4310	4462165	Trim, prune tree	34.5
4460365	66	0.14	Field	6221	4462156	Trim, prune tree	34.5
4461554	46	0.05	Field	6311	4462166	Trim, prune tree	34.5
5317716	37	1.22	Field	6322	5323351	Trim, prune tree	34.5
5368704	30	0.14	Field	6311	5370675	Trim, prune tree	34.5
5368962	104	2.74	Field	6310	5370677	Trim, prune tree	34.5
5368964	106	0.09	Field	6310	5370677	Trim, prune tree	34.5
5368988	130	0.41	Field	6310	5370677	Trim, prune tree	34.5
7443250	22	1.44	Field	6310	5370677	Trim, prune tree	34.5
7443252	22	1.45	Field	6311	5370677	Trim, prune tree	34.5
7443943	24	2.20	Field	6310	4462166	Trim, prune tree	34.5
7443952	24	1.55	Field	6310	4462166	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	**Voltage**
4461460	126	0.69	Pasture	7341	4462165	Trim, prune tree	34.5
4461479	3	2.07	Pasture	7211	4462166	Trim, prune tree	34.5
4461480	4	0.23	Pasture	7111	4462166	Trim, prune tree	34.5
5368913	54	0.12	Pasture	7311	5370677	Trim, prune tree	34.5
5368948	90	0.92	Pasture	7310	5370677	Trim, prune tree	34.5
7443922	140	1.14	Pasture	7310	5370674	Trim, prune tree	34.5
7444431	47	1.36	Pasture	7311	4462166	Trim, prune tree	34.5
4460241	37	0.69	Residential	5310	4462155	Trim, prune tree	34.5
4460361	62	0.50	Residential	5321	4462156	Trim, prune tree	34.5
4460366	67	0.80	Residential	5311	4462156	Trim, prune tree	34.5
4460368	69	1.72	Residential	5311	4462156	Trim, prune tree	34.5
4460564	7	0.29	Residential	5211	4462158	Trim, prune tree	34.5
4460572	15	0.71	Residential	5311	4462158	Trim, prune tree	34.5
4460599	42	8.28	Residential	5311	4462158	Trim, prune tree	34.5
4460605	48	0.97	Residential	5321	4462158	Trim, prune tree	34.5
4460607	50	1.11	Residential	5310	4462158	Trim, prune tree	34.5
4461241	2	2.43	Residential	5310	4462164	Trim, prune tree	34.5
4461259	20	0.26	Residential	5311	4462164	Trim, prune tree	34.5
4461264	25	0.29	Residential	5330	4462164	Trim, prune tree	34.5
4461276	37	0.44	Residential	5310	4462164	Trim, prune tree	34.5
4461283	44	0.69	Residential	5311	4462164	Trim, prune tree	34.5
4461290	47	0.22	Residential	5311	4462164	Trim, prune tree	34.5
4461307	16	0.51	Residential	5320	4462165	Trim, prune tree	34.5
4461313	22	1.20	Residential	5000	4462165	Trim, prune tree	34.5
4461333	42	0.02	Residential	5321	4462165	Trim, prune tree	34.5
4461335	44	0.35	Residential	5221	4462165	Trim, prune tree	34.5
4461341	50	0.55	Residential	5000	4462165	Trim, prune tree	34.5
4461347	55	2.82	Residential	5000	4462165	Trim, prune tree	34.5
4461356	64	0.60	Residential	5311	4462165	Trim, prune tree	34.5
4461376	84	3.22	Residential	5000	4462165	Trim, prune tree	34.5
4461428	94	0.23	Residential	5320	4462165	Trim, prune tree	34.5
4461432	98	2.07	Residential	5321	4462165	Trim, prune tree	34.5
4461433	99	0.78	Residential	5211	4462165	Trim, prune tree	34.5
4461434	100	0.64	Residential	5211	4462165	Trim, prune tree	34.5
4461547	39	0.37	Residential	5310	4462166	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
4461549	41	0.34	Residential	5310	4462166	Trim, prune tree	34.5
4461552	44	0.25	Residential	5310	4462166	Trim, prune tree	34.5
4461578	48	0.20	Residential	5310	4462166	Trim, prune tree	34.5
4461581	51	0.10	Residential	5311	4462166	Trim, prune tree	34.5
4461589	59	0.26	Residential	5310	4462166	Trim, prune tree	34.5
4461660	129	0.40	Residential	5320	4462166	Trim, prune tree	34.5
4461680	149	0.88	Residential	5331	4462166	Trim, prune tree	34.5
4461683	152	0.79	Residential	5311	4462166	Trim, prune tree	34.5
4461692	4	0.11	Residential	5310	4462167	Trim, prune tree	34.5
4530935	26	0.73	Residential	5332	4535869	Trim, prune tree	34.5
4530937	28	0.62	Residential	5331	4535869	Trim, prune tree	34.5
4530945	38	0.35	Residential	5321	4535869	Trim, prune tree	34.5
4530947	41	12.44	Residential	5331	4535869	Trim, prune tree	34.5
4530991	80	0.71	Residential	5211	4535869	Trim, prune tree	34.5
4531383	16	1.80	Residential	5221	4535855	Trim, prune tree	34.5
5237201	12	0.72	Residential	5310	5241855	Trim, prune tree	34.5
5308919	13	0.40	Residential	5322	5323114	Trim, prune tree	34.5
5308957	52	0.35	Residential	5322	5323114	Trim, prune tree	34.5
5308973	68	0.33	Residential	5321	5323114	Trim, prune tree	34.5
5309008	104	0.91	Residential	5311	5323114	Trim, prune tree	34.5
5309026	122	0.36	Residential	5311	5323114	Trim, prune tree	34.5
5309185	6	0.43	Residential	5310	5323117	Trim, prune tree	34.5
5309201	20	0.69	Residential	5323	5323117	Trim, prune tree	34.5
5310101	69	1.78	Residential	5321	5323118	Trim, prune tree	34.5
5310143	109	0.25	Residential	5310	5323118	Trim, prune tree	34.5
5310175	137	2.01	Residential	5310	5323118	Trim, prune tree	34.5
5310221	184	1.94	Residential	5321	5323118	Trim, prune tree	34.5
5314528	5	0.77	Residential	5321	5323245	Trim, prune tree	34.5
5314572	5	0.07	Residential	5331	5323246	Trim, prune tree	34.5
5315649	1	3.77	Residential	5320	5323288	Trim, prune tree	34.5
5315651	3	0.34	Residential	5320	5323288	Trim, prune tree	34.5
5315652	4	0.22	Residential	5311	5323288	Trim, prune tree	34.5
5315666	3	2.07	Residential	5322	5323289	Trim, prune tree	34.5
5315667	4	3.66	Residential	5321	5323289	Trim, prune tree	34.5
5315669	7	1.00	Residential	5311	5323289	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	**Voltage**
5315692	20	0.42	Residential	5320	5323289	Trim, prune tree	34.5
5315698	26	1.46	Residential	5321	5323289	Trim, prune tree	34.5
5315701	29	2.49	Residential	5331	5323289	Trim, prune tree	34.5
5315957	4	0.17	Residential	5310	5323295	Trim, prune tree	34.5
5315958	5	0.50	Residential	5311	5323295	Trim, prune tree	34.5
5315962	9	0.58	Residential	5310	5323295	Trim, prune tree	34.5
5315979	26	0.30	Residential	5310	5323295	Trim, prune tree	34.5
5315994	41	0.46	Residential	5311	5323295	Trim, prune tree	34.5
5316031	66	2.00	Residential	5323	5323295	Trim, prune tree	34.5
5316042	76	0.26	Residential	5320	5323295	Trim, prune tree	34.5
5316074	94	0.65	Residential	5321	5323295	Trim, prune tree	34.5
5316265	7	0.24	Residential	5000	5323342	Trim, prune tree	34.5
5316268	10	0.05	Residential	5311	5323342	Trim, prune tree	34.5
5316270	12	0.31	Residential	5311	5323342	Trim, prune tree	34.5
5316872	24	0.55	Residential	5000	5323339	Trim, prune tree	34.5
5317683	4	0.14	Residential	5310	5323351	Trim, prune tree	34.5
5317719	40	0.06	Residential	5322	5323351	Trim, prune tree	34.5
5317729	50	0.84	Residential	5320	5323351	Trim, prune tree	34.5
5317733	54	2.87	Residential	5322	5323351	Trim, prune tree	34.5
5318492	32	1.14	Residential	5312	5323389	Trim, prune tree	34.5
5318495	35	0.66	Residential	5321	5323389	Trim, prune tree	34.5
5318506	45	1.15	Residential	5312	5323389	Trim, prune tree	34.5
5318608	146	0.40	Residential	5311	5323389	Trim, prune tree	34.5
5318611	149	0.78	Residential	5332	5323389	Trim, prune tree	34.5
5318614	152	0.34	Residential	5322	5323389	Trim, prune tree	34.5
5318673	210	0.20	Residential	5330	5323389	Trim, prune tree	34.5
5318716	252	2.00	Residential	5321	5323389	Trim, prune tree	34.5
5318791	327	1.92	Residential	5311	5323389	Trim, prune tree	34.5
5319690	23	0.22	Residential	5311	5323411	Trim, prune tree	34.5
5321770	5	1.17	Residential	5311	5323454	Trim, prune tree	34.5
5321775	10	1.94	Residential	5310	5323454	Trim, prune tree	34.5
5321777	12	2.66	Residential	5310	5323454	Trim, prune tree	34.5
5321778	13	0.94	Residential	5330	5323454	Trim, prune tree	34.5
5321780	15	0.45	Residential	5320	5323454	Trim, prune tree	34.5
5321782	17	0.45	Residential	5310	5323454	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5321784	19	1.34	Residential	5311	5323454	Trim, prune tree	34.5
5321789	24	0.63	Residential	5310	5323454	Trim, prune tree	34.5
5321791	26	0.95	Residential	5320	5323454	Trim, prune tree	34.5
5321809	40	2.47	Residential	5310	5323454	Trim, prune tree	34.5
5321811	42	0.54	Residential	5310	5323454	Trim, prune tree	34.5
5321813	44	1.05	Residential	5311	5323454	Trim, prune tree	34.5
5368548	10	0.60	Residential	5331	5370674	Trim, prune tree	34.5
5368560	22	0.12	Residential	5310	5370674	Trim, prune tree	34.5
5368577	39	1.38	Residential	5332	5370674	Trim, prune tree	34.5
5368620	82	0.82	Residential	5311	5370674	Trim, prune tree	34.5
5368634	96	0.12	Residential	5311	5370674	Trim, prune tree	34.5
5368638	100	0.25	Residential	5311	5370674	Trim, prune tree	34.5
5368647	109	0.27	Residential	5311	5370674	Trim, prune tree	34.5
5368728	23	0.21	Residential	5311	5370676	Trim, prune tree	34.5
5368731	26	1.33	Residential	5322	5370676	Trim, prune tree	34.5
5368783	78	0.32	Residential	5331	5370676	Trim, prune tree	34.5
5368810	105	0.53	Residential	5311	5370676	Trim, prune tree	34.5
5368840	6	0.94	Residential	5141	5370677	Trim, prune tree	34.5
5368920	61	0.09	Residential	5310	5370677	Trim, prune tree	34.5
5368922	63	1.41	Residential	5320	5370677	Trim, prune tree	34.5
5368952	94	2.07	Residential	5311	5370677	Trim, prune tree	34.5
5368953	95	0.05	Residential	5311	5370677	Trim, prune tree	34.5
5368956	98	0.06	Residential	5310	5370677	Trim, prune tree	34.5
5368960	102	0.89	Residential	5321	5370677	Trim, prune tree	34.5
5368965	107	2.53	Residential	5310	5370677	Trim, prune tree	34.5
7443248	22	0.34	Residential	5310	5370677	Trim, prune tree	34.5
7443254	22	0.50	Residential	5320	5370677	Trim, prune tree	34.5
7443282	22	2.03	Residential	5311	5370677	Trim, prune tree	34.5
7443750	7	0.39	Residential	5311	4462156	Trim, prune tree	34.5
7443776	40	0.35	Residential	5311	4462156	Trim, prune tree	34.5
7443931	23	1.00	Residential	5310	4462166	Trim, prune tree	34.5
7443942	24	0.34	Residential	5310	4462166	Trim, prune tree	34.5
7443947	24	0.24	Residential	5310	4462166	Trim, prune tree	34.5
7444168	22	2.91	Residential	5311	5370677	Trim, prune tree	34.5
7444169	22	0.68	Residential	5311	5370677	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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7444425	23	0.29	Residential	5311	4462166	Trim, prune tree	34.5
7444430	47	0.55	Residential	5310	4462166	Trim, prune tree	34.5
7444433	47	0.47	Residential	5310	4462166	Trim, prune tree	34.5
7444437	47	0.37	Residential	5310	4462166	Trim, prune tree	34.5
7444438	47	1.00	Residential	5310	4462166	Trim, prune tree	34.5
7444441	47	0.69	Residential	5311	4462166	Trim, prune tree	34.5
7444451	4	3.51	Residential	5321	4462167	Trim, prune tree	34.5
7444578	15	0.74	Residential	5321	4555137	Trim, prune tree	34.5
7463229	61	0.35	Residential	5310	5323295	Trim, prune tree	34.5
7463234	61	0.09	Residential	5310	5323295	Trim, prune tree	34.5
7463244	88	0.54	Residential	5310	5323295	Trim, prune tree	34.5
7463364	59	0.21	Residential	5311	5323351	Trim, prune tree	34.5
7587498	69	0.49	Residential	5331	5323115	Trim, prune tree	34.5
7840890	9	0.34	Residential	5331	5323214	Trim, prune tree	34.5
7841043	39	2.62	Residential	5320	4535869	Trim, prune tree	34.5
4460363	64	1.48	Road Crossing	3332	4462156	Trim, prune tree	34.5
4460565	8	0.05	Road Crossing	3211	4462158	Trim, prune tree	34.5
4460596	39	0.96	Road Crossing	3311	4462158	Trim, prune tree	34.5
4461289	46	0.32	Road Crossing	3322	4462164	Trim, prune tree	34.5
4461293	2	0.34	Road Crossing	3311	4462165	Trim, prune tree	34.5
4461304	13	4.85	Road Crossing	3310	4462165	Trim, prune tree	34.5
4461541	33	0.05	Road Crossing	3111	4462166	Trim, prune tree	34.5
4461667	136	0.55	Road Crossing	3321	4462166	Trim, prune tree	34.5
4461669	138	0.46	Road Crossing	3221	4462166	Trim, prune tree	34.5
4461760	30	0.85	Road Crossing	3310	4462167	Trim, prune tree	34.5
4530992	81	8.62	Road Crossing	3310	4535869	Trim, prune tree	34.5
4532573	69	4.84	Road Crossing	3231	4535909	Trim, prune tree	34.5
4553945	2	0.30	Road Crossing	3321	4555137	Trim, prune tree	34.5
5308920	14	2.44	Road Crossing	3330	5323114	Trim, prune tree	34.5
5309118	67	0.28	Road Crossing	3310	5323115	Trim, prune tree	34.5
5313861	4	0.52	Road Crossing	3321	5323214	Trim, prune tree	34.5
5314407	9	0.59	Road Crossing	3310	5323206	Trim, prune tree	34.5
5314524	1	0.34	Road Crossing	3310	5323245	Trim, prune tree	34.5
5315665	2	0.32	Road Crossing	3320	5323289	Trim, prune tree	34.5
5315671	8	1.57	Road Crossing	3310	5323289	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5315688	17	0.91	Road Crossing	3000	5323289	Trim, prune tree	34.5
5316853	5	0.30	Road Crossing	3310	5323339	Trim, prune tree	34.5
5316894	45	1.51	Road Crossing	3321	5323339	Trim, prune tree	34.5
5316940	16	1.93	Road Crossing	3311	5323340	Trim, prune tree	34.5
5316945	21	0.57	Road Crossing	3222	5323340	Trim, prune tree	34.5
5316954	30	0.29	Road Crossing	3311	5323340	Trim, prune tree	34.5
5317697	18	0.32	Road Crossing	3331	5323351	Trim, prune tree	34.5
5318628	166	0.50	Road Crossing	3000	5323389	Trim, prune tree	34.5
5318657	194	1.38	Road Crossing	3332	5323389	Trim, prune tree	34.5
5318675	212	0.84	Road Crossing	3000	5323389	Trim, prune tree	34.5
5319684	17	0.14	Road Crossing	3310	5323411	Trim, prune tree	34.5
5368553	15	0.20	Road Crossing	3331	5370674	Trim, prune tree	34.5
5368575	37	0.34	Road Crossing	3322	5370674	Trim, prune tree	34.5
5368578	40	2.14	Road Crossing	3212	5370674	Trim, prune tree	34.5
5368582	44	1.81	Road Crossing	3312	5370674	Trim, prune tree	34.5
5368670	4	1.14	Road Crossing	3310	5370675	Trim, prune tree	34.5
5368762	57	0.06	Road Crossing	3320	5370676	Trim, prune tree	34.5
5368828	110	0.76	Road Crossing	3320	5370676	Trim, prune tree	34.5
5368830	112	0.89	Road Crossing	3312	5370676	Trim, prune tree	34.5
5368885	27	1.06	Road Crossing	3313	5370677	Trim, prune tree	34.5
5368901	42	0.27	Road Crossing	3000	5370677	Trim, prune tree	34.5
5368979	121	1.18	Road Crossing	3310	5370677	Trim, prune tree	34.5
7443920	138	0.31	Road Crossing	3311	5370674	Trim, prune tree	34.5
7444167	22	0.42	Road Crossing	3311	5370677	Trim, prune tree	34.5
7444269	80	0.69	Road Crossing	3311	4462165	Trim, prune tree	34.5
7444302	83	0.13	Road Crossing	3311	4462165	Trim, prune tree	34.5
7444462	29	0.13	Road Crossing	3311	4462167	Trim, prune tree	34.5
7587596	1	0.30	Road Crossing	3312	5323289	Trim, prune tree	34.5
7841044	40	0.25	Road Crossing	3321	4535869	Trim, prune tree	34.5
7841053	74	0.96	Road Crossing	3221	4535869	Trim, prune tree	34.5
4461242	3	0.70	Streams	1310	4462164	Trim, prune tree	34.5
4461305	14	0.28	Streams	1331	4462165	Trim, prune tree	34.5
4461332	41	1.37	Streams	1321	4462165	Trim, prune tree	34.5
5316269	11	0.93	Streams	1323	5323342	Trim, prune tree	34.5
5368730	25	0.86	Streams	1322	5370676	Trim, prune tree	34.5

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
5368812	107	1.63	Streams	1311	5370676	Trim, prune tree	34.5
7444170	22	0.12	Streams	1322	5370677	Trim, prune tree	34.5
7444450	4	0.80	Streams	1311	4462167	Trim, prune tree	34.5
5310056	23	0.92	Wetlands	2332	5323118	Trim, prune tree	34.5
4461263	24	0.43	Woodlands	9210	4462164	Trim, prune tree	34.5
5308995	91	1.44	Woodlands	9331	5323114	Trim, prune tree	34.5
5310057	24	0.40	Woodlands	9232	5323118	Trim, prune tree	34.5
5316939	15	0.23	Woodlands	9330	5323340	Trim, prune tree	34.5
5368574	36	0.18	Woodlands	9311	5370674	Trim, prune tree	34.5
5368685	11	0.14	Woodlands	9312	5370675	Trim, prune tree	34.5
5368826	108	0.12	Woodlands	9221	5370676	Trim, prune tree	34.5
5368925	66	2.02	Woodlands	9112	5370677	Trim, prune tree	34.5
7443915	135	0.25	Woodlands	9331	5370674	Trim, prune tree	34.5
5232000	101	0.53	Brush Lands	8213	5241777	Cut, stump treat and chip	46
5232167	25	0.44	Commercial/Inc	4110	5241786	Cut, stump treat and chip	46
5231814	37	0.46	Residential	5321	5241790	Cut, stump treat and chip	46
5232482	3	0.54	Residential	5312	5241759	Cut, stump treat and chip	46
5231801	25	0.32	Road Crossing	3110	5241794	Cut, stump treat and chip	46
5231997	98	0.72	Road Crossing	3320	5241777	Cut, stump treat and chip	46
7445598	3	0.00	Road Crossing	3110	5241790	Cut, stump treat and chip	46
5232534	53	0.59	Woodlands	9340	5241759	Cut, stump treat and chip	46
5232152	11	0.91	Commercial/Inc	4322	5241786	Trim, prune tree	46
5231800	24	0.94	Cropland	6000	5241794	Trim, prune tree	46
5231816	39	0.41	Residential	5310	5241790	Trim, prune tree	46
5231900	1	1.15	Residential	5330	5241777	Trim, prune tree	46
5231923	24	0.33	Residential	5212	5241777	Trim, prune tree	46
5231925	26	0.50	Residential	5320	5241777	Trim, prune tree	46
5232001	103	0.61	Residential	5311	5241777	Trim, prune tree	46
5232082	178	1.29	Residential	5312	5241777	Trim, prune tree	46
5232086	182	0.28	Residential	5311	5241777	Trim, prune tree	46
5232561	75	0.20	Residential	5320	5241759	Trim, prune tree	46
5232605	116	0.28	Residential	5321	5241759	Trim, prune tree	46
5231988	89	0.19	Road Crossing	3311	5241777	Trim, prune tree	46
5232058	154	0.84	Road Crossing	3321	5241777	Trim, prune tree	46
7841106	102	0.37	Road Crossing	3311	5241777	Trim, prune tree	46

Projected CY2012 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
7566142	131	1.02	Commercial/Inc	4110	7841110	Cut, stump treat and chip	69
7566044	51	1.28	Cropland	6000	4535948	Cut, stump treat and chip	69
7304688	77	0.83	Residential	5210	7841111	Cut, stump treat and chip	69
7566137	122	0.62	Residential	5111	7841111	Cut, stump treat and chip	69
7566161	150	0.60	Residential	5111	7841110	Cut, stump treat and chip	69
7841090	104	0.95	Residential	5310	4535919	Cut, stump treat and chip	69
4533472	20	0.51	Road Crossing	3111	4535925	Cut, stump treat and chip	69
4533737	27	0.64	Road Crossing	3311	4535919	Cut, stump treat and chip	69
4533771	56	0.34	Road Crossing	3323	4535919	Cut, stump treat and chip	69
4535095	21	0.48	Road Crossing	3310	4535952	Cut, stump treat and chip	69
4535098	24	0.39	Road Crossing	3323	4535952	Cut, stump treat and chip	69
4535100	26	0.56	Road Crossing	3113	4535952	Cut, stump treat and chip	69
4535118	45	0.94	Road Crossing	3111	4535952	Cut, stump treat and chip	69
7566136	121	0.45	Road Crossing	3211	7841111	Cut, stump treat and chip	69
7566143	132	1.18	Road Crossing	3211	7841110	Cut, stump treat and chip	69
7840861	3	0.14	Road Crossing	3232	4535952	Cut, stump treat and chip	69
7566045	52	0.34	Streams	1212	4535948	Cut, stump treat and chip	69
4535117	44	1.24	Field	6000	4535952	Mechanical brush mowing	69
4535134	57	7.11	Woodlands	9322	4535952	Mechanical brush mowing	69
7840869	86	0.23	Woodlands	9212	4535952	Mechanical brush mowing	69
4533749	39	2.30	Residential	5331	4535919	Trim, prune tree	69
4535097	23	0.60	Residential	5321	4535952	Trim, prune tree	69
4535213	115	2.08	Residential	8331	4535952	Trim, prune tree	69
7566078	81	3.14	Residential	5321	7841111	Trim, prune tree	69
7566080	83	2.38	Residential	5311	7841111	Trim, prune tree	69
7566159	148	0.28	Residential	5311	7841110	Trim, prune tree	69
4533797	74	0.12	Road Crossing	3312	4535919	Trim, prune tree	69
4535186	110	0.26	Road Crossing	3321	4535952	Trim, prune tree	69
4535388	1	0.67	Road Crossing	3311	7841111	Trim, prune tree	69
7566059	63	0.36	Road Crossing	3310	7841111	Trim, prune tree	69
7566149	138	0.52	Road Crossing	3311	7841110	Trim, prune tree	69
7566151	140	0.54	Road Crossing	3331	7841110	Trim, prune tree	69
4459028	30	1.11	Brush Lands	8211	4462143	Cut, stump treat and chip	115
4531449	20	0.52	Brush Lands	8233	4535856	Cut, stump treat and chip	115
7566383	130	0.53	Brush Lands	8222	7841193	Cut, stump treat and chip	115

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
7442870	268	0.00	Commercial/Inc	4320	5241933	Cut, stump treat and chip	115
7442872	270	0.00	Commercial/Inc	4330	5241933	Cut, stump treat and chip	115
7443183	12	1.32	Commercial/Inc	4310	4555128	Cut, stump treat and chip	115
7443605	182	1.69	Commercial/Inc	4210	4462143	Cut, stump treat and chip	115
7443909	62	0.72	Commercial/Inc	4331	5323207	Cut, stump treat and chip	115
4459046	48	1.76	Pasture	7311	4462143	Cut, stump treat and chip	115
7443690	18	5.14	Pasture	7332	5241743	Cut, stump treat and chip	115
4459031	33	0.62	Residential	5332	4462143	Cut, stump treat and chip	115
4459296	4	3.73	Residential	5232	4462184	Cut, stump treat and chip	115
4459314	24	5.16	Residential	5322	4462184	Cut, stump treat and chip	115
4459329	39	2.19	Residential	5322	4462184	Cut, stump treat and chip	115
4459337	47	1.10	Residential	5323	4462184	Cut, stump treat and chip	115
4459348	58	1.07	Residential	5242	4462184	Cut, stump treat and chip	115
4459393	103	0.53	Residential	5322	4462184	Cut, stump treat and chip	115
4459677	48	10.19	Residential	5221	4462185	Cut, stump treat and chip	115
5307970	212	3.31	Residential	5311	5323076	Cut, stump treat and chip	115
5310667	209	0.12	Residential	5221	5323076	Cut, stump treat and chip	115
5313542	43	1.33	Residential	5211	5323207	Cut, stump treat and chip	115
5316647	45	2.60	Residential	5311	5323337	Cut, stump treat and chip	115
5317491	7	2.45	Residential	5000	5323347	Cut, stump treat and chip	115
5317494	9	3.29	Residential	5310	5323347	Cut, stump treat and chip	115
5370140	20	4.23	Residential	5232	5370630	Cut, stump treat and chip	115
5370142	22	0.94	Residential	5210	5370630	Cut, stump treat and chip	115
5370146	26	2.47	Residential	5210	5370630	Cut, stump treat and chip	115
4459293	1	0.35	Road Crossing	3321	4462184	Cut, stump treat and chip	115
4459307	16	0.11	Road Crossing	3232	4462184	Cut, stump treat and chip	115
4459349	59	2.63	Road Crossing	3311	4462184	Cut, stump treat and chip	115
4459634	4	3.30	Road Crossing	3210	4462185	Cut, stump treat and chip	115
4531446	17	1.12	Road Crossing	3320	4535856	Cut, stump treat and chip	115
5236475	6	2.83	Road Crossing	3320	5241830	Cut, stump treat and chip	115
5236491	20	1.19	Road Crossing	3341	5241830	Cut, stump treat and chip	115
5237156	42	0.60	Road Crossing	3322	5241842	Cut, stump treat and chip	115
5307948	184	2.39	Road Crossing	3311	5323076	Cut, stump treat and chip	115
5307973	213	4.71	Road Crossing	3321	5323076	Cut, stump treat and chip	115
5313482	10	0.33	Road Crossing	3233	5323207	Cut, stump treat and chip	115

Projected CY2012 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
5313486	14	0.59	Road Crossing	3313	5323207	Cut, stump treat and chip	115
5313528	34	0.25	Road Crossing	3223	5323207	Cut, stump treat and chip	115
5314142	15	0.50	Road Crossing	3220	5323218	Cut, stump treat and chip	115
5314145	19	3.90	Road Crossing	3211	5323218	Cut, stump treat and chip	115
7443910	62	0.27	Road Crossing	3321	5323207	Cut, stump treat and chip	115
7566311	81	0.23	Road Crossing	3110	7841193	Cut, stump treat and chip	115
7566327	92	0.61	Road Crossing	3221	7841193	Cut, stump treat and chip	115
7566389	136	0.74	Road Crossing	3223	7841193	Cut, stump treat and chip	115
7566443	256	0.86	Road Crossing	6000	7841195	Cut, stump treat and chip	115
4459330	40	0.07	Streams	1212	4462184	Cut, stump treat and chip	115
4459390	100	2.34	Streams	1333	4462184	Cut, stump treat and chip	115
5307788	37	0.50	Streams	1310	5323076	Cut, stump treat and chip	115
4459310	20	2.29	Woodlands	9333	4462184	Cut, stump treat and chip	115
4531581	118	0.90	Brush Lands	8323	4535867	Mechanical brush mowing	115
5307851	97	0.52	Brush Lands	8222	5323076	Mechanical brush mowing	115
5368452	6	5.93	Brush Lands	8233	5370669	Mechanical brush mowing	115
5368453	6	3.16	Brush Lands	8111	5370669	Mechanical brush mowing	115
5368467	9	10.67	Brush Lands	8223	5370669	Mechanical brush mowing	115
5368469	11	17.34	Brush Lands	8233	5370669	Mechanical brush mowing	115
5368472	14	11.39	Brush Lands	8213	5370669	Mechanical brush mowing	115
5369244	19	0.29	Brush Lands	8223	5370656	Mechanical brush mowing	115
5369312	72	4.43	Brush Lands	8121	5370656	Mechanical brush mowing	115
5370137	17	5.94	Brush Lands	8233	5370630	Mechanical brush mowing	115
5370145	25	5.68	Brush Lands	8233	5370630	Mechanical brush mowing	115
7566320	86	1.28	Brush Lands	8341	7841193	Mechanical brush mowing	115
5369240	15	2.30	Residential	5222	5370656	Mechanical brush mowing	115
7566382	129	1.43	Residential	5311	7841193	Mechanical brush mowing	115
4459118	115	0.52	Streams	1221	4462143	Mechanical brush mowing	115
5369241	16	1.10	Streams	1223	5370655	Mechanical brush mowing	115
4531579	118	0.75	Wetlands	2213	4535856	Mechanical brush mowing	115
4459008	10	3.62	Woodlands	9232	4462143	Mechanical brush mowing	115
4459117	114	6.41	Woodlands	9231	4462143	Mechanical brush mowing	115
4459119	116	2.88	Woodlands	9231	4462143	Mechanical brush mowing	115
4459160	157	1.24	Woodlands	9333	4462143	Mechanical brush mowing	115
4459220	33	0.11	Woodlands	9333	4462133	Mechanical brush mowing	115

Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	Voltage
4459696	67	1.17	Woodlands	9231	4462185	Mechanical brush mowing	115
5369242	17	2.26	Woodlands	9223	5370656	Mechanical brush mowing	115
5369246	21	0.52	Woodlands	9223	5370656	Mechanical brush mowing	115
5369310	70	10.39	Woodlands	9132	5370656	Mechanical brush mowing	115
7304311	168	1.83	Woodlands	9222	7841194	Mechanical brush mowing	115
7443173	6	3.98	Woodlands	9223	5370669	Mechanical brush mowing	115
4459000	2	3.34	Brush Lands	8000	4462143	Trim, prune tree	115
4459069	66	4.34	Brush Lands	8311	4462144	Trim, prune tree	115
4459169	166	0.69	Brush Lands	8311	4462143	Trim, prune tree	115
4459294	2	3.41	Brush Lands	8233	4462184	Trim, prune tree	115
4459306	15	0.54	Brush Lands	8311	4462184	Trim, prune tree	115
4459375	85	2.45	Brush Lands	8322	4462184	Trim, prune tree	115
5235766	112	1.80	Brush Lands	8322	5241813	Trim, prune tree	115
5235776	122	0.78	Brush Lands	8311	5241813	Trim, prune tree	115
7445214	18	0.97	Brush Lands	8333	5241743	Trim, prune tree	115
4554205	8	2.05	Commercial/Inc	4320	4555128	Trim, prune tree	115
4554971	4	0.98	Commercial/Inc	4320	4555126	Trim, prune tree	115
7443015	32	4.95	Commercial/Inc	4311	4462148	Trim, prune tree	115
7443178	11	2.27	Commercial/Inc	4002	4555128	Trim, prune tree	115
4458459	23	2.23	Field	6310	4462148	Trim, prune tree	115
4459196	11	0.07	Field	6321	4462133	Trim, prune tree	115
7442931	37	2.15	Field	6210	4462133	Trim, prune tree	115
4459223	36	3.67	Pasture	7211	4462133	Trim, prune tree	115
4458463	27	0.47	Residential	5321	4462148	Trim, prune tree	115
4458999	1	2.63	Residential	5311	4462143	Trim, prune tree	115
4459007	9	0.21	Residential	5310	4462143	Trim, prune tree	115
4459013	15	0.81	Residential	5311	4462143	Trim, prune tree	115
4459015	17	0.16	Residential	5311	4462143	Trim, prune tree	115
4459132	129	0.71	Residential	5310	4462143	Trim, prune tree	115
4459205	19	1.72	Residential	5311	4462133	Trim, prune tree	115
4459216	29	3.74	Residential	5341	4462133	Trim, prune tree	115
4459347	57	7.68	Residential	5320	4462184	Trim, prune tree	115
4459369	79	3.72	Residential	5222	4462184	Trim, prune tree	115
4459380	90	0.15	Residential	5333	4462184	Trim, prune tree	115
4459383	93	0.64	Residential	5321	4462184	Trim, prune tree	115

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Projected CY2012 Floor Trim Acres

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System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
4459389	99	4.38	Residential	5321	4462184	Trim, prune tree	115
4459391	101	1.07	Residential	5321	4462184	Trim, prune tree	115
4459402	112	0.51	Residential	5310	4462184	Trim, prune tree	115
4459404	114	0.22	Residential	5310	4462184	Trim, prune tree	115
4459646	16	0.09	Residential	5321	4462185	Trim, prune tree	115
4459648	18	2.48	Residential	5311	4462185	Trim, prune tree	115
4459650	20	0.34	Residential	5310	4462185	Trim, prune tree	115
4459765	3	0.30	Residential	5311	4462182	Trim, prune tree	115
4459779	12	3.51	Residential	5321	4462182	Trim, prune tree	115
4459780	13	2.58	Residential	5311	4462182	Trim, prune tree	115
4554206	9	1.61	Residential	5330	4555128	Trim, prune tree	115
4554207	10	4.95	Residential	5331	4555128	Trim, prune tree	115
5235556	37	0.91	Residential	5220	5241812	Trim, prune tree	115
5235712	61	5.19	Residential	5321	5241813	Trim, prune tree	115
5235767	113	0.35	Residential	5311	5241813	Trim, prune tree	115
5235773	119	1.05	Residential	5000	5241813	Trim, prune tree	115
5236489	18	0.63	Residential	5320	5241830	Trim, prune tree	115
5237146	32	8.01	Residential	5000	5241842	Trim, prune tree	115
5307784	32	3.65	Residential	5321	5323076	Trim, prune tree	115
5307786	34	0.55	Residential	5321	5323076	Trim, prune tree	115
5307793	41	4.38	Residential	5110	5323076	Trim, prune tree	115
5310643	43	2.24	Residential	5321	5323076	Trim, prune tree	115
5310645	55	5.88	Residential	5211	5323076	Trim, prune tree	115
5310646	56	0.23	Residential	5000	5323076	Trim, prune tree	115
5316632	29	1.20	Residential	5000	5323337	Trim, prune tree	115
5369230	5	3.10	Residential	5331	5370656	Trim, prune tree	115
5369231	6	3.82	Residential	5321	5370656	Trim, prune tree	115
5369235	10	10.28	Residential	5332	5370656	Trim, prune tree	115
5369237	12	15.50	Residential	5001	5370656	Trim, prune tree	115
7443168	6	0.83	Residential	5321	5370669	Trim, prune tree	115
7443288	11	1.94	Residential	5310	4555128	Trim, prune tree	115
7443289	11	2.72	Residential	5310	4555128	Trim, prune tree	115
7443583	70	1.17	Residential	5311	4462185	Trim, prune tree	115
7443722	18	0.32	Residential	5313	5241743	Trim, prune tree	115
7444736	131	0.00	Residential	5311	5241830	Trim, prune tree	115

NM 123 DPS 88 DSM-4

Projected CY2012 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2012.

System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
4458438	2	0.15	Road Crossing	3310	4462148	Trim, prune tree	115
4458448	12	0.92	Road Crossing	3333	4462148	Trim, prune tree	115
4458457	21	0.11	Road Crossing	3331	4462148	Trim, prune tree	115
4459014	16	1.14	Road Crossing	3310	4462143	Trim, prune tree	115
4459037	39	1.04	Road Crossing	3311	4462143	Trim, prune tree	115
4459047	49	0.61	Road Crossing	3321	4462143	Trim, prune tree	115
4459066	66	1.07	Road Crossing	3331	4462144	Trim, prune tree	115
4459174	171	0.10	Road Crossing	3000	4462143	Trim, prune tree	115
4459222	35	2.18	Road Crossing	3311	4462133	Trim, prune tree	115
4459366	76	1.89	Road Crossing	3310	4462184	Trim, prune tree	115
4459694	65	1.75	Road Crossing	3310	4462185	Trim, prune tree	115
4531413	2	0.58	Road Crossing	3322	4535856	Trim, prune tree	115
4531442	13	1.00	Road Crossing	3311	4535856	Trim, prune tree	115
4531448	19	0.57	Road Crossing	3310	4535856	Trim, prune tree	115
4531510	51	0.26	Road Crossing	3312	4535856	Trim, prune tree	115
4532882	147	1.44	Road Crossing	3311	7841194	Trim, prune tree	115
5237122	8	0.60	Road Crossing	3321	5241842	Trim, prune tree	115
5237130	16	0.23	Road Crossing	3310	5241842	Trim, prune tree	115
5313460	7	3.34	Road Crossing	3111	5323178	Trim, prune tree	115
5313483	11	0.34	Road Crossing	3310	5323207	Trim, prune tree	115
5313513	19	0.22	Road Crossing	3313	5323207	Trim, prune tree	115
5313545	46	0.70	Road Crossing	3223	5323207	Trim, prune tree	115
5313551	52	0.08	Road Crossing	3223	5323207	Trim, prune tree	115
5313556	57	0.47	Road Crossing	3311	5323207	Trim, prune tree	115
5314685	37	0.51	Road Crossing	3310	5323243	Trim, prune tree	115
5369228	3	0.80	Road Crossing	3310	5370656	Trim, prune tree	115
5369236	11	0.92	Road Crossing	3110	5370656	Trim, prune tree	115
5369262	37	0.56	Road Crossing	3310	5370656	Trim, prune tree	115
5369294	54	0.11	Road Crossing	3310	5370656	Trim, prune tree	115
5369300	60	3.16	Road Crossing	3311	5370656	Trim, prune tree	115
5369304	64	0.30	Road Crossing	3310	5370656	Trim, prune tree	115
7443007	7	0.16	Road Crossing	3310	4462182	Trim, prune tree	115
7443719	37	0.29	Road Crossing	3310	4462184	Trim, prune tree	115
7463748	39	1.50	Road Crossing	3310	5323207	Trim, prune tree	115
7463756	39	2.66	Road Crossing	3000	5323207	Trim, prune tree	115

Projected CY2012 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2012.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	*Voltage*
4459124	121	2.03	Streams	1341	4462143	Trim, prune tree	115
4459374	84	0.91	Streams	1311	4462184	Trim, prune tree	115
4459654	24	1.34	Streams	1313	4462185	Trim, prune tree	115
5235768	114	1.15	Streams	1211	5241813	Trim, prune tree	115
5369229	4	0.46	Streams	1321	5370656	Trim, prune tree	115
5369232	7	0.23	Streams	1322	5370656	Trim, prune tree	115
5369287	47	0.80	Streams	1123	5370656	Trim, prune tree	115
4554198	2	1.15	Wetlands	2310	4555128	Trim, prune tree	115
4459067	66	1.94	Woodlands	9241	4462144	Trim, prune tree	115
5236487	16	0.46	Woodlands	9231	5241830	Trim, prune tree	115
5321617	37	0.11	Woodlands	9233	5323447	Trim, prune tree	115
5311250	104	2.24	Road Crossing	3221	5323267	Cut, stump treat and chip	345
5311232	89	2.01	Residential	5320	5323267	Trim, prune tree	345
5319719	16	7.02	Residential	5310	5323401	Trim, prune tree	345
7444684	79	0.00	Residential	5321	5323440	Trim, prune tree	345
7444128	156	0.96	Road Crossing	3312	5323267	Trim, prune tree	345
	Total:	**884.16**	**acres**				

Projected CY2013 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2013.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	**Voltage**
5239943	4	1.69	Residential	5321	5241917	Cut, stump treat and chip	23
5239657	12	0.41	Road Crossing	3312	5241910	Cut, stump treat and chip	23
5369705	10	0.36	Brush Lands	8331	5370639	Trim, prune tree	23
5369709	14	0.61	Brush Lands	8331	5370639	Trim, prune tree	23
5369696	1	4.07	Commercial/Industrial	4320	5370639	Trim, prune tree	23
5239759	2	0.44	Field	6310	5241913	Trim, prune tree	23
5239655	10	0.18	Residential	5310	5241910	Trim, prune tree	23
5239779	25	2.14	Residential	5330	5241913	Trim, prune tree	23
5239780	26	0.22	Residential	5330	5241913	Trim, prune tree	23
5239782	28	0.55	Residential	5311	5241913	Trim, prune tree	23
5239786	32	0.36	Residential	5311	5241913	Trim, prune tree	23
5239803	49	0.23	Residential	5311	5241913	Trim, prune tree	23
5239945	6	1.57	Residential	5311	5241917	Trim, prune tree	23
5239968	27	0.23	Residential	5330	5241917	Trim, prune tree	23
7442732	1.13	0	Residential	5320	5241902	Trim, prune tree	23
5239717	1	0.26	Road Crossing	3311	5241912	Trim, prune tree	23
5239799	45	0.27	Road Crossing	3330	5241913	Trim, prune tree	23
5239807	53	0.42	Streams	1211	5241913	Trim, prune tree	23
5238849	48	0.3	Road Crossing	3310	5241888	Trim, prune tree	34.5
5369447	1	2.55	Commercial/Industrial	4311	5370635	Trim, prune tree	34.5
5369448	2	7.3	Commercial/Industrial	4310	5370635	Trim, prune tree	34.5
7463312	1.05	0.32	Brush Lands	8320	5241888	Trim, prune tree	34.5
5237246	16	1.65	Brush Lands	8322	5241849	Cut, stump treat and chip	46
5237232	2	0.22	Residential	5311	5241849	Cut, stump treat and chip	46
5237244	14	0.12	Residential	5110	5241849	Cut, stump treat and chip	46
5237256	27	1.01	Residential	5331	5241849	Cut, stump treat and chip	46
5237267	38	1.12	Residential	5221	5241849	Cut, stump treat and chip	46
5237271	42	0.48	Residential	5330	5241849	Cut, stump treat and chip	46
5237306	79	0.47	Residential	5321	5241849	Cut, stump treat and chip	46
5240435	19	0.38	Residential	5221	5241849	Cut, stump treat and chip	46
5237231	1	0.32	Road Crossing	3321	5241849	Cut, stump treat and chip	46
5237265	36	0.43	Road Crossing	3310	5241849	Cut, stump treat and chip	46
5237281	52	0.22	Road Crossing	3223	5241849	Cut, stump treat and chip	46
5237245	15	0.29	Streams	1223	5241849	Cut, stump treat and chip	46

Projected CY2013 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2013.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	**Voltage**
5237278	49	0.88	Commercial/Industrial	4320	5241849	Trim, prune tree	46
5237282	53	1.35	Commercial/Industrial	4320	5241849	Trim, prune tree	46
5237247	17	0.12	Residential	5331	5241849	Trim, prune tree	46
5237264	35	1.31	Residential	5310	5241849	Trim, prune tree	46
5237257	28	0.34	Road Crossing	3311	5241849	Trim, prune tree	46
5237279	50	1.06	Road Crossing	3321	5241849	Trim, prune tree	46
5368537	3	0.11	Road Crossing	3310	5370673	Trim, prune tree	69
4530435	81.00	0.08	Brush Lands	8333	4535838	Cut, stump treat and chip	115
5235830	9.00	0.46	Brush Lands	8321	5241814	Cut, stump treat and chip	115
5236392	35.00	1.36	Brush Lands	8332	5241811	Cut, stump treat and chip	115
5236393	36.00	3.63	Brush Lands	8323	5241811	Cut, stump treat and chip	115
5308005	3.04	1.11	Brush Lands	8121	5323098	Cut, stump treat and chip	115
5308042	26.00	0.31	Brush Lands	8331	5323097	Cut, stump treat and chip	115
5316540	266.00	0.32	Brush Lands	8313	5323336	Cut, stump treat and chip	115
7445019	109.22	0.81	Brush Lands	8212	5241814	Cut, stump treat and chip	115
4530355	8.00	2.30	Residential	5311	4535838	Cut, stump treat and chip	115
4530373	24.00	1.68	Residential	5332	4535843	Cut, stump treat and chip	115
4530418	66.00	1.38	Residential	5310	4535844	Cut, stump treat and chip	115
4530357	10.00	0.80	Road Crossing	3111	4535838	Cut, stump treat and chip	115
4530365	15.00	0.68	Road Crossing	3311	4535838	Cut, stump treat and chip	115
4530370	19.00	0.27	Road Crossing	3220	4535843	Cut, stump treat and chip	115
4530449	94.00	0.86	Road Crossing	3340	4535838	Cut, stump treat and chip	115
4530451	96.00	1.04	Road Crossing	3311	4535838	Cut, stump treat and chip	115
5235831	10.00	0.62	Road Crossing	3220	5241814	Cut, stump treat and chip	115
5235916	95.00	0.66	Road Crossing	3311	5241814	Cut, stump treat and chip	115
5308009	3.08	0.73	Road Crossing	3222	5323098	Cut, stump treat and chip	115
5308017	3.16	0.17	Road Crossing	3111	5323098	Cut, stump treat and chip	115
5308025	6.00	0.42	Road Crossing	3222	5323097	Cut, stump treat and chip	115
5316410	139.00	0.63	Road Crossing	3322	5323336	Cut, stump treat and chip	115
5316549	275.00	1.25	Road Crossing	3321	5323336	Cut, stump treat and chip	115
5316842	52.00	1.34	Road Crossing	3222	5323338	Cut, stump treat and chip	115
7444979	101.10	0.35	Road Crossing	3320	5241814	Cut, stump treat and chip	115
7444995	104.17	3.05	Road Crossing	3331	5241814	Cut, stump treat and chip	115
5319113	116.00	1.92	Streams	1310	5323381	Cut, stump treat and chip	115

Projected CY2013 Floor Trim Acres

Note: These numbers are from the previous floor trim cycle. Final numbers (acres) will be recorded upon completion of the individual inventories in early 2013.

System Id	*Site Number*	*Site Area (Acres)*	*Land Use*	*Land Use Code*	*Forestry Segment*	*Prescription*	**Voltage**
4459972	182.00	5.81	Woodlands	9223	4462181	Mechanical brush mowing	115
7445044	153.05	5.45	Woodlands	9343	5241814	Mechanical brush mowing	115
4460067	264.00	1.73	Brush Lands	8140	4462181	Trim, prune tree	115
5236406	58.00	0.12	Brush Lands	8313	5241811	Trim, prune tree	115
5316499	226.00	0.11	Brush Lands	8312	5323336	Trim, prune tree	115
4459840	50.00	1.08	Pasture	7222	4462152	Trim, prune tree	115
4458472	502.00	0.36	Residential	5312	4462147	Trim, prune tree	115
4458476	506.00	0.70	Residential	5322	4462147	Trim, prune tree	115
4459794	4.00	0.75	Residential	5311	4462152	Trim, prune tree	115
4459799	9.00	0.80	Residential	5221	4462152	Trim, prune tree	115
4459816	26.00	1.21	Residential	5320	4462152	Trim, prune tree	115
4554303	25.00	3.30	Residential	5111	4555124	Trim, prune tree	115
4555050	49.00	1.00	Residential	5310	4555124	Trim, prune tree	115
5233461	129.00	0.89	Residential	5311	5241755	Trim, prune tree	115
5236358	17.00	0.05	Residential	5310	5241811	Trim, prune tree	115
5308058	40.02	4.58	Residential	5310	5323089	Trim, prune tree	115
5319102	105.00	0.56	Residential	5310	5323381	Trim, prune tree	115
7583406	49.00	2.55	Residential	5321	4462152	Trim, prune tree	115
4458473	503.00	1.11	Road Crossing	3210	4462147	Trim, prune tree	115
4458475	505.00	0.19	Road Crossing	3310	4462147	Trim, prune tree	115
4458478	508.00	0.98	Road Crossing	3331	4462147	Trim, prune tree	115
4459806	16.00	0.94	Road Crossing	3321	4462152	Trim, prune tree	115
4459990	197.03	0.30	Road Crossing	3310	4462153	Trim, prune tree	115
4460026	223.00	0.12	Road Crossing	3312	4462181	Trim, prune tree	115
4554288	10.00	1.00	Road Crossing	3310	4555124	Trim, prune tree	115
4554304	26.00	0.81	Road Crossing	3311	4555124	Trim, prune tree	115
4554369	95.00	2.11	Road Crossing	3320	4555124	Trim, prune tree	115
5235902	81.00	1.58	Road Crossing	3310	5241814	Trim, prune tree	115
5236004	130.00	0.85	Road Crossing	3210	5241814	Trim, prune tree	115
5236838	10.00	0.27	Road Crossing	3310	5241840	Trim, prune tree	115
7445020	109.23	0.59	Road Crossing	3311	5241814	Trim, prune tree	115
7445476	6.03	0.43	Road Crossing	3321	5241818	Trim, prune tree	115
7583293	106.10	0.83	Road Crossing	3332	4462181	Trim, prune tree	115
7583404	256.10	0.81	Woodlands	3321	4462181	Trim, prune tree	115

Date of Request: March 2, 2010
Due Date: March 12, 2010

Request No. VVP-3
NMPC Req. No. NM 167 DPS 97

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Vijay Puran

TO: Infrastructure and Operations Panel

Request:

For each transmission project listed in Exhibit_ (IOP-14), Schedule 2, Exhibit 2 (Sheets 126 through 130 of 308), please provide the actual capital expenditures for fiscal years ending 2006, 2007, 2008, 2009, and 2010 (use budgeted capital expenditures for months where actuals are not available for FY 2010). Please also provide the total project spending for each project as of January 31, 2010. Please provide the requested information in Excel, in the same format (and project sequence) as Exhibit_ (IOP-14), Schedule 2, Exhibit 2.

Response:

Please see WP-3 Attachment 1 (VVP-3_Attach 1). The Transmission capital expenditures provided include actuals from FY2006 to January 31, 2010, and 2 months of forecast expenditures for February and March 2010.

Name of Respondent:
Tom Sullivan

Date of Reply:
March 11, 2010

Spending Rationale	Program	Project Name	Project Number	FY06	FY07	FY08	FY09	FY10 (thru 1/31)	Total FY06-10 spend (thru 1/31/10)	Feb-Mar FY10 Forecast	Total FY06-FY10	Risk Score
Asset Condition	3A/3B Tower Strategy	Leeds - Pleasant Valley 91/92 Tower Reinforcement - includes public s	C08017						-	-	-	49
		New Scotland - Leeds 93/94 Tower Reinforcement - Public Safety	C07918						-	-	-	49
	3A/3B Tower Strategy Total								-	-	-	
	Battery Strategy	Battery Strategy FY09 Co. 36 Txt	C24239			12,372	331,071	109,104	452,547	-	452,547	22
		Battery System Replacement Program	C32957					48,204	48,204	4,523	52,727	34
		BatteryRplStrategyCo36TxT	C33847					99,485	99,485	74,014	173,499	39
	Battery Strategy Total			-	-	**12,372**	**331,071**	**256,793**	**600,236**	**78,537**	**678,772**	
	Circuit Breaker Replacement Strategy	Inghams-replace 115kv OCB	C31661					13,383	13,383	(3,408)	9,975	35
		Meco - Replace 115kV PTs and circuit breakers	CNYAS24						-	-	-	35
		Mortimer 115kV - refurbish / replace circuit breakers	CNYAS39						-	-	-	35
		NY Circuit Breaker Replacement (Priority 4)	CNYAS07						-	-	-	35
		NY Circuit Breaker Replacement Priority 3)	CNYAS06						-	-	-	26
	Circuit Breaker Replacement Strategy Total								-	-	-	
	Flying Ground Strategy	Strategy to Replace Flying Ground Switches	CNYX30						-	-	-	22
	Flying Ground Strategy Total								-	-	-	
	Other Asset Condition	Alps #188 Obsolete Circuit Switcher	C28304						-	-	-	16
		Ash to Teall Cathodic Protection Upgrade	C27082						-	-	-	28
		Bristol Hill Repl SWs 46 & 47	C31005				2,401		2,401	-	2,401	28
		Butler Sta 64 -RPL LN182	C31950						-	-	-	43
		Colton Replace CBs and disconnects	C29844				10,631	20	10,651	15,980	26,631	34
		Dewitt-Rebuild 345kv	C31867					104,827	104,827	(4,827)	100,000	49
		Dunkirk 230kV Control Cable TB1	C27845				13,926	48,318	62,244	131,682	193,926	34
		Edic Station - Replace TB2, 3, 4 Metering	C31025						-	-	-	40
		EJ West-Warrensburg 9 115kV Cross Bracing	C03383						-	-	-	16
		Elm Terminal Station - HPFF Alarms	C30528						-	-	-	35
		Elnora 115kV Tap Cross Bracing	C03384						-	-	-	16
		Fenner-Cortland 3 Cross Braces.	C03281						-	-	-	21
		Gardenville Control Cables	C27829				17,482	13,694	31,177	6,306	37,483	34
		Gardenville Station - HPFF Alarms	C30530						-	-	-	35
		Gibson Sta - Repl SW1602,03, R1617,18	C31004				12,129	4	12,133	(1)	12,133	28
		Greenbush- Replace TB3	C31663						-	-	-	39
		Harper Station - Replace 2023 & 2033 MODs	C29950				2,559		2,559	-	2,559	22
		Huntley Station - HPFF Alarming	C30631					3,056	3,056	(3,056)	-	35
		Lafayette - Replace Line 4 Relaying	C28044				262,311	320,086	582,397	163,414	745,811	39
		Leeds SVC-Refurbishment/Replacement	C03748	75,913	1,079	1,609	36,737	1,578,880	1,694,218	621,120	2,315,338	36
		New Gardenville - TB3 &TB#4	C27042			182	2,804,787	2,791,457	5,596,426	473,543	6,069,969	34
		NY Surge Arrester Replacement	C31658						-	-	-	36
		Oswego - Replace Special	C29216					904	904	24,096	25,000	35
		Packard Replace TB3 &TB4	C27006			182	1,655,237	21,267	1,676,687	433,733	2,110,420	41
		PIW Prospective Projects	CNYX72						-	-	-	49
		Porter Replace 11 GE 230kV RF2 Discs	C20912			6,601	1,004	2,367	9,972	633	10,605	28
		Rochester Generator and HPFF Alarms	C30532						-	-	-	39
		Rochester HPFF Cable Plant	C15988		15,802	9,628	594		26,023	-	26,023	44
		Rochester Pump - LPFF Trip Scheme	C29946				3,895		3,895	-	3,895	35
		Silver Creek switch structure - replace 115kV disconnects	CNYAS38						-	-	-	21
		Taylorville Repl SW #23	C31044				1,648		1,648	-	1,648	34
		Temple Pressuring Plant	CNYX26						-	-	-	28
		Ticonderoga-Sanford T6410R Removal	C32309						-	-	-	43
		Trinity UG Pumphouse Redesign	C11318		375	47,113	(39,162)	616	8,941	384	9,325	49
		Youngmann Terminal Station - Replace Switch #310	C29951				1,657		1,657	-	1,657	19

Other Asset Condition Total			**75,913**	**17,256**	**65,314**	**4,787,835**	**4,885,497**	**9,831,816**	**1,863,007**	**11,694,822**	
Overhead Line Refurbishment Program	Dunkirk - Falconer #161	CNYAS62						-	-	-	40
	Dunkirk - Falconer #162	CNYAS49						-	-	-	44
	Falconer-HH 153-154, T1160-T1170 ACR	C27422				455		455	-	455	39
	Gard-Dun 141-142 T1260-1270 ACR	C03389			47,107	202,708	223,013	472,827	66,987	539,814	44
	Gardenville - Buffalo Sw #146 [145]	CNYAS60						-	-	-	18
	Gardenville - Dunkirk #74	CNYAS75						-	-	-	40
	Gardenville -HH 151-152, T1950-T1280-S ACR	C27425					25,593	25,593	24,407	50,000	39
	Gardenville Lines 180-182, T1660-T1780 ACR	C27436						-	-	-	44
	Gard-HHI 151-152, T1950-T1280 N ACR	C04718	587,868	564,226	165,934	388,539	8,244,389	9,950,955	4,255,611	14,206,566	49
	Homer Hill Bennett Rd 157, T1340 ACR	C27429						-	-	-	39
	Huntley - Lockport #37	CNYAS53						-	-	-	44
	Huntley - Praxair #46	CNYAS51						-	-	-	18
	Huntley-Gardenville 38 [& 39] (refurb)	CNYAS63						-	-	-	40
	Indeck Oswego - Lighthouse Hill #2	CNYAS56						-	-	-	39
	Lockport 103- 104, T1620-T106 STR	C27432						-	-	-	40
	Lockport Mortimer 111 T1530 ACR	C03417			54,777	158,708	448,559	662,044	46,441	708,485	49
	Lockport-Batavia 112, T1510 ACR	C03422				448		448	-	448	39
	Lockport-Bativa 108 Refurb	C27431						-	-	-	29
	Lockport-Mort 113-114, T1540-T1550 LER	C18670			61,674	188,702	2,148,892	2,399,268	6,351,108	8,750,376	49
	Lockprt-Mort 111 Tap T1530-1 Refurb	C33014						-	-	-	39
	Mortimer - Pannell Road #24	CNYAS65						-	-	-	40
	Pannell-Geneva 4-4A, T1860 ACR	C30889						-	-	-	37
	Porter - Rotterdam #30	CNYAS77						-	-	-	40
	Porter Rotterdam 31, T4210 ACR	C30890						-	-	-	45
	Taylorville -B 5-6 T3320-T3330 ACR	C27437					72,435	72,435	(72,435)	-	39
	Taylorville-Moshier 7, T3340 ACR	C24361			3,776	49,436	49,896	103,108	50,000	153,108	49
	Ticonderoga Lines 2 [& 3] (Complete Line)	CNYAS82						-	-	-	40
	Ticonderoga-2-3, T5810-T5830 SXR	C19530			82,899	371,908	772,620	1,227,428	2,727,380	3,954,808	49
Overhead Line Refurbishment Program Total			**587,868**	**564,226**	**416,167**	**1,360,904**	**11,985,397**	**14,914,562**	**13,449,499**	**28,364,060**	
Relay Replacement Strategy	Browns Falls - protection repalcement and new control building	CNYAS29						-	-	-	19
	Edic - Protection replacement	CNYAS31						-	-	-	19
	Geres lock Control room & Relay Strategy	CNYAS90						-	-	-	19
	Menands - new control building	CNYAS41						-	-	-	28
	North Troy - protection replacement	CNYAS26						-	-	-	19
	NY Protection & Control Replacement	CNYAS10						-	-	-	35
	Oswego - new control building	CNYAS32						-	-	-	19
	Relay Replacement Strategy - Phase 2	CNYAS88						-	-	-	19
	Riverside Control room & Relay Strategy	CNYAS89						-	-	-	19
	Yahnundasis - protection replacement	CNYAS28						-	-	-	19
Relay Replacement Strategy Total								-	-	-	
RHE Breaker Replacement	Lighthouse Hill Road - Repl R60 RHE PCB	C24299			1,128	145		1,273	-	1,273	39
	Oneida - R/R 115kV FP RHE OCB's	C18410			4,129	604		4,733	-	4,733	39
RHE Breaker Replacement Total			**-**	**-**	**5,256**	**749**	**-**	**6,005**	**-**	**6,005**	
Shield Wire Strategy	Shieldwire: Buffalo 145	C28683				1,092	570	1,662	9,430	11,092	40
	Shieldwire: Clay-Dewitt 3	C28709				20,403	31,916	52,319	28,084	80,403	40
	Shieldwire: Gardenville -Depew 54	C28706				1,397	2,699	4,095	7,301	11,397	40
	Shieldwire: Gardenville Homer 151/152	C28679				2,286	38,170	40,457	6,830	47,287	40
	Shieldwire: Huntley - Gardenville 38	C28676				10,778	29,766	40,544	10,234	50,778	40
	Shieldwire: Huntley-Lockport 36/37	C28707				7,377	31,289	38,666	40,000	78,666	40
	Shieldwire: LaFarge Pleasant Vl. 8	C28678				40,246	2,522,485	2,562,731	1,523,486	4,086,217	40
	Shieldwire: Mountain-Lockport 103	C28681				8,230	628,682	636,912	721,318	1,358,230	40
	Shieldwire: Walck Rd - Huntley	C28712				5,874	39,081	44,955	40,000	84,955	40
Shield Wire Strategy Total						**97,683**	**3,324,658**	**3,422,341**	**2,386,684**	**5,809,025**	
Steel Tower Strategy	S. Oswego Lighthouse Hill Circuits	C21693			6,090	123,660	258,125	387,875	61,875	449,750	49
Steel Tower Strategy Total					**6,090**	**123,660**	**258,125**	**387,875**	**61,875**	**449,750**	
Substation Rebuilds	Buffalo 115kV - replace disconnects	CNYAS40						-	-	-	21
	Dunkirk Rebuild	C05155				396		396	-	396	35

		Elm St. Refurbishment	CNYAS91						-	-	-	35
		Gardenville Rebuild	C05156					264,268	264,268	145,887	410,155	35
		Gardenville Rebuild Line Location	C30084					39,838	39,838	25,162	65,000	44
		LightHH 115kv Yard Repl & cntrl hse	C31662						-	-	-	35
		Lockport Rebuild	CNYAS2						-	-	-	35
		Mohican - rebuild including transformers and oil circuit breakers	CNYAS44						-	-	-	35
		N. Leroy Rebuild Station	C29180				27,158	226,423	253,581	118,577	372,158	34
		Porter 230kV - replace disconnects and PTs	CNYAS36						-	-	-	28
		Reynolds Road - protection repalcement & new control building $ repla	CNYAS27						-	-	-	19
		Rome 115 kV Station	C03778						-	25,000	25,000	22
		Rotterdam R/R 230kV FPE RHE CB's	C17849			37,655	9,815		47,470	-	47,470	39
	Substation Rebuilds Total					-	27,554	530,529	558,083	314,626	872,709	
	Transformer Replacement Strategy	NY 115kv Transformer Replace (Priority 4)	C31656						-	-	-	41
	Transformer Replacement Strategy Total								-	-	-	
	U-Series Relay Strategy	Edic FE1 - Replace U Series Relays	C24662					33,449	33,449	96,551	130,000	33
		Leeds - Replace U Series Relays	C24663					14,716	14,716	16,284	31,000	33
		LN17- Replace Type U Relays	C24661			3,622	8,239	47,892	59,753	15,108	74,861	33
		Westinghouse U Series Relay Strategy	C05150			13,552	12,109	68,209	93,870	21,791	115,661	33
	U-Series Relay Strategy Total					17,175	20,348	130,816	168,339	53,183	221,522	
	Reserve	Resreve	CNYX31						-	-	-	49
	Reserve Total								-	-	-	
Asset Condition Total				663,781	581,482	522,373	6,749,804	21,371,816	29,889,256	18,207,410	48,096,666	
Damage/Failure	NY Inspection Projects	NY Inspection Projects - Capital	C26923			2,170	290,945	1,237,549	1,530,664	140,000	1,670,664	49
	NY Inspection Projects Total					2,170	290,945	1,237,549	1,530,664	140,000	1,670,664	
	Other Damage/Failure	Curtis St- Repl LN10 &13 Relays	C29320				4,583		4,583	-	4,583	26
		Geres Lock Sub- Repl 14 115kV Disc	C28324				692	3	696	17,622	18,317	19
		Getzville-Sta60-Repl Cntrl Hse Roof	C32504					1,979	1,979	21	2,000	35
		Kensington Sub Repl TB#4 & 5 LTC Control	C28303				3,777	17,437	21,214	47,563	68,777	28
		Leeds - PV 92 T5330 Str 361	C32964						-	-	-	40
		New Gardenville-Repl 230kV Discs	C20546		8,272	9,734	115,120	2,590	135,715	5,410	141,125	27
		Oneida - TB#3 Failure	C22391			679,158	(16,550)	1,080,203	1,742,811	19,797	1,762,608	49
		Oneida Sub- Replace LTG & Recpt Ckts	C28964				5,365		5,365	-	5,365	16
		Porter Sub - Repl. Barre neutr & Auto	C32596						-	10,000	10,000	35
		Replace Damaged Insulators	C31660						-	-	-	40
		S. Oswego R/R LN1 Tone Package	C18952		452	3,122	2,403	27	6,004	1,773	7,776	33
		Transmission Line Replacements - Budgetary Reserve	C03278	416,503	471,991	1,198,954	218,183		2,305,631	-	2,305,631	49
		Transmission Station Failures - Budgetary Reserve	C03792	652,954	825,501	931,782	927,912	1,254,967	4,593,118	45,033	4,638,150	49
		Transmission Storm Budgetary Reserve	C03481	3,543	370,764	174,384	362,652		911,342	-	911,342	49
		Transmission UG C Budgetary Reserve - Co 36	C13622		1,850	46,490	(48,340)		-	-	-	49
		Yahnundasis - Repl 18 & 28 Switches	C26144			2,040	16,323	145,996	164,359	104,004	268,363	28
	Other Damage/Failure Total			1,073,000	1,678,830	3,045,664	1,592,120	2,503,202	9,892,816	251,222	10,144,038	
	Steel Tower Strategy	Visual Grade 6 Tower Replacements	C25539						-	-	-	40
	Steel Tower Strategy Total								-	-	-	
	Wood Pole Strategy	Wood Pole Management - NY	C11640				107,107	298,722	405,829	130,000	535,829	43
	Wood Pole Strategy Total						107,107	298,722	405,829	130,000	535,829	
Damage/Failure Total				1,073,000	1,678,830	3,047,834	1,990,172	4,039,473	11,829,309	521,222	12,350,531	
Statutory/Regulatory	Clay Station Rebuild	Clay Station Line Project	C32539					15,028	15,028	59,972	75,000	49
	Clay Station Rebuild Total							15,028	15,028	59,972	75,000	
	Clearance Strategy	Oswego Lafayette 17, T2420 CCR	C31141				16,174		16,174	-	16,174	33
		Transmission Tower Clearances	C03256	67,254	709,720	(42,759)	38,852		773,067	-	773,067	40
	Clearance Strategy Total			67,254	709,720	(42,759)	55,026	-	789,241	-	789,241	
	Digital Fault Recorder Strategy	Digital Fault Recorder Strategy	C03726	449,986	387,493	402,663	1,016,056	806,284	3,062,482	273,715	3,336,197	49
		Repl DFR at Non-BPS Stations	C29487						-	-	-	27
	Digital Fault Recorder Strategy Total			449,986	387,493	402,663	1,016,056	806,284	3,062,482	273,715	3,336,197	
	Generation	Alabama Ledge Wind-Loop in, Loop-out	CNYX63						-	-	-	49
		Alabama Ledge Wind-Loop in, Loop-out Reimburseable portion	CNYX63R						-	-	-	49
		Alabama Ledge Wind-RTU/Metering/Relay upgrades	CNYX64						-	-	-	49
		Alabama Ledge Wind-RTU/Metering/Relay upgrades-Reimbursable po	CNYX64R						-	-	-	49

	Athens Generation Expansion -Permanent Line	CNYX01						-	-	-	1
	Athens Generation Expansion -Permanent Line Reimbursable	CNYX01R						-	-	-	1
	Athens Generation Expansion -Permanent Sub	CNYX02						-	-	-	1
	Athens Generation Expansion -Permanent Sub Reimbursable	CNYX02R						-	-	-	1
	BEDCO Substation Work	C23413			(1,507,314)	783,452	(1,546,832)	(2,270,693)	2,844,369	573,676	49
	Cape Vincent Wind-RTU/Metering/Relay upgrades	CNYX60						-	-	-	49
	Cape Vincent Wind-RTU/Metering/Relay upgrades-Reimbursable	CNYX60R						-	-	-	49
	Clayton Wind-Loop in, Loop-out	CNYX70						-	-	-	49
	Clayton Wind-Loop in, Loop-out Reimburseable portion	CNYX70R						-	-	-	49
	Clayton Wind-RTU/Metering/Relay upgrades	CNYX71						-	-	-	49
	Clayton Wind-RTU/Metering/Relay upgrades-Reimbursable portion	CNYX71R						-	-	-	49
	Fairfield Wind Farm Interconnection	C29583					11,625	11,625	38,375	50,000	49
	Fairfield Wind Farm Interconnection - Reimbursbale Portion	C29583R						-	(50,000)	(50,000)	49
	Fairfield Wind-loop in loop out	C29782					4,686	4,686	45,314	50,000	49
	Fairfield Wind-loop in loop out(reimb)	C29782R						-	(50,000)	(50,000)	49
	Green Power-Cody Rd-loop in,loop out	CNYX68						-	-	-	49
		CNYX68R						-	-	-	49
	Green Power-Cody Rd-RTU,metering	CNYX69						-	-	-	49
		CNYX69R						-	-	-	49
	Inghams SPS updates	CNYPL3						-	-	-	40
	Jordanville Wind-Loop in,Loop out	CNYX53						-	-	-	49
	Jordanville Wind-Loop in,Loop out Reimbursable Portion	CNYX53R						-	-	-	49
	Jordanville Wind-RTU/metering/Relay upgrades	CNYX54						-	-	-	49
	Jordanville Wind-RTU/metering/Relay upgrades Reimbursable Portion	CNYX54R						-	-	-	49
	New Grange Wind-Loop in, Loop-out	CNYX65						-	-	-	49
	New Grange Wind-Loop in, Loop-out Reimburseable portion	CNYX65R						-	-	-	49
	New Grange Wind-RTU/Metering/Relay upgrades	CNYX66						-	-	-	49
	New Grange Wind-RTU/Metering/Relay upgrades-Reimbursable portio	CNYX66R						-	-	-	49
	Noble Bliss 1 - New Arcade Tap	C27745				8,339	11,479	19,819	783,091	802,909	49
	Noble Bliss 1 - New Arcade Tap - Reimbursable Portion	C27745R						-	(799,635)	(799,635)	49
	Noble Bliss Wind Farm	C24981			580,474	(570,751)	30,422	40,145	512,271	552,416	35
	Noble Bliss Wind Farm - Reimbursbale Portion	C24981R						-	(557,693)	(557,693)	49
	Sherman Island Uprate-RTU/Metering/Relay upgrades	CNYX67						-	-	-	49
	Sherman Island Uprate-RTU/Metering/Relay upgrades-Reimbursable p	CNYX67R						-	-	-	49
	St Lawrence Wind-Loop in, Loop-out	CNYX55						-	-	-	49
	St Lawrence Wind-Loop in, Loop-out Reimburseable Portion	CNYX55R						-	-	-	49
	St Lawrence Wind-RTU/Metering/Relay upgrades	CNYX56						-	-	-	49
	St Lawrence Wind-RTU/Metering/Relay upgrades-Reimbursable Portio	CNYX56R						-	-	-	49
	WestHill Wind -Loop in-loop out	CNYX49						-	-	-	49
	WestHill Wind -Loop in-loop out Reimbursable Portion	CNYX49R						-	-	-	49
	WestHill Wind -RTU/metering	CNYX50						-	-	-	49
	WestHill Wind-RTU/metering Reimbursable Portion	CNYX50R						-	-	-	49
Generation Total					**(926,840)**	**221,041**	**(1,488,620)**	**(2,194,419)**	**2,766,093**	**571,674**	
Load	New Distribution for Load Growth	CNYPL8						-	-	-	30
	Reynolds Road 115-13.2Kv Second Bank	C27423			1,149	352,462	246,417	600,027	972,857	1,572,884	35
	Unifax	C29824				2,262		2,262	-	2,262	49
	Unifax -Reimbursbale Portion	C29824R						-	-	-	49
Load Total					**1,149**	**354,724**	**246,417**	**602,289**	**972,857**	**1,575,146**	
Luther Forest	Luther Forest Relay and Malta Sub work	C22738			1,424	230,750	303,728	535,901	396,272	932,173	49
Luther Forest Total					**1,424**	**230,750**	**303,728**	**535,901**	**396,272**	**932,173**	
Northeast Region Reinforcement	Design/Build NERR	CNYX39						-	-	-	36
	Re-conductor Rotterdam 1&2 Lines - Part of NERR	C18250		13,984	491,977	141,240	3,348,093	3,995,295	2,193,907	6,189,202	49
	Rotterdam Banks - Part of NERR	CNYX39A						-	-	-	36
	Spier Rotterdam Line#3 - Part of NERR	C31418				2,598	1,472,552	1,475,150	242,011	1,717,161	49
	Turner Rd new 230-115kV Station - Part of NERR	C31326				1,304	724,094	725,398	275,906	1,001,304	49
	Turner Road New Line Taps - Part of NERR	C31419				624	129,234	129,858	20,766	150,624	49
Northeast Region Reinforcement Total				**13,984**	**491,977**	**145,766**	**5,673,973**	**6,325,701**	**2,732,590**	**9,058,291**	
Other Statutory/Regulatory	Repl 23 meters Interconnect/ NYISO	C29483				58,082	57,900	115,982	321,050	437,032	49

		Various Station - Range Operations	C32551						-	-	-	49
	Other Statutory/Regulatory Total						**58,082**	**57,900**	**115,982**	**321,050**	**437,032**	
	RTU Strategy	RTU Replacements NERC, EMS, Obsolescence	C03772	582,433	1,582,624	2,230,589	3,351,270	2,177,846	9,924,763	557,154	10,481,917	49
	RTU Strategy Total			**582,433**	**1,582,624**	**2,230,589**	**3,351,270**	**2,177,846**	**9,924,763**	**557,154**	**10,481,917**	
	Station BPS Upgrades	Porter - 115kV upgrade to bulk power	C28686					36,288	36,288	63,712	100,000	40
		Upgrade 115kV Clay Sub to BPS NPCC	C28705				69,064	634,458	703,522	215,542	919,064	49
	Station BPS Upgrades Total						**69,064**	**670,746**	**739,811**	**279,254**	**1,019,064**	
	Reserve	Resreve	CNYX32		-				-	-	-	49
	Reserve Total								-	-	-	
Statutory/Regulatory Total				**1,099,673**	**2,693,821**	**2,158,202**	**5,501,779**	**8,463,302**	**19,916,778**	**8,358,957**	**28,275,735**	
	Frontier Region	Refurbishment of Huntley 230kV Station	C11496						-	-	-	22
		Tonawanda Station - Line Work	C11494		61,106	147,163	572,175	95,302	875,747	104,698	980,445	49
		Tonawanda Station - Station Work	C11495		510,836	1,932,338	(1,307,422)	710,872	1,846,625	179,128	2,025,753	49
	Frontier Region Total				**571,943**	**2,079,501**	**(735,246)**	**806,174**	**2,722,372**	**283,826**	**3,006,198**	
	Load	Frankhauser New Station - T Line Work	C30744						-	-	-	41
		Install Second Transformer - Inman Rd	C30765					10,154	10,154	9,469	19,623	39
		Replace TB#1 - Everett Rd	C30824						-	-	-	30
	Load Total							**10,154**	**10,154**	**9,469**	**19,623**	
	Other System Capacity & Performance	Albany Steam - Add 2nd Station svc	C22071			213	125	2	340	(2)	338	16
		BlackRiver-LHHX5-2 LB Attachment	C33744						-	-	-	49
		BlackRiver-Taylorville#2 New Switch	C33742						-	-	-	43
		Boonville-Rome #4 Reconductoring	CNYPL4						-	-	-	40
		Dewitt 345kV Breaker Install	C21353			44	62	10	116	(10)	106	6
		East Watertown 115 Mobile tap	C32337						-	-	-	49
		Eastern NY 115kV Capacitor Additions	CNYPL7						-	-	-	35
		Farmington 11 Line Rearrangement	C28384				185	906	1,091	(906)	185	49
		Farmington 11 Line Rearrangement - Reimb portion	C28384R						-	-	-	49
		Fourth Elm 230-23kV Bank (N-1-1)	CNYPL14						-	-	-	28
		Fourth Sawyer 230-23kV Bank (N-1-1)	CNYPL13						-	-	-	26
		Install Capacitance/TRV	CNYPL34						-	-	-	33
		Install new Alps Site Sub- Nassau	C30806					1,688	1,688	4,877	6,565	27
		Install new Alps Site Sub-Line Work	C33619						-	-	-	49
		Lake Colby - Spare SVC Transformer and Thyristor Reactor	CNYPL29						-	-	-	28
		Lowville Automated 115 kV Switches	C32259						-	-	-	49
		LTC Filtration Systems NY	C24064						-	-	-	21
		Reconductor 24 & 25 Line - Hogan Taps to Panell Road	CNYPL33						-	-	-	35
		Reconductor Black River LHH	CNYPL1						-	-	-	40
		Replace N. Angola 115:34.5kV Banks	C27163						-	-	-	36
		Replace overdutied 115kV breakers at Central and Mohawk Valley	CNYPL26						-	-	-	39
		Replace overdutied 115kV breakers at Maplewood	CNYPL25						-	-	-	39
		Replace three 115kV breakers at ALCOA	CNYPL24						-	-	-	39
		Reynolds Road - Cap Blocking Scheme	C29964				3,952	5	3,957	19,995	23,952	28
		Spier West 9 115kv Switch Add	C30826						-	-	-	34
		Sta Homer Hill Transformers	C10705						-	-	-	20
		Syracuse Area Reconductoring	CNYPL28						-	-	-	19
		Transmission Study Budgetary Reserve -NY	C08376	77,762	380,078	(164,882)	265,138		558,096	-	558,096	49
		Upgrade Breakers at Scriba	C28708				26,225	466,691	492,916	983,309	1,476,224	40
		Upgrade Breakers at Volney	C33252					64,073	64,073	165,927	230,000	49
		Upgrade Niagara-Pakard #195	C29945				8,345		8,345	-	8,345	40
	Other System Capacity & Performance Total			**77,762**	**380,078**	**(164,625)**	**304,032**	**533,375**	**1,130,622**	**1,173,190**	**2,303,812**	
	Overhead Line Refurbishment Program	Browns Falls - Taylorville 4 Lightning Enhancements	C24359			5,885	66,345	81,414	153,643	80,000	233,643	37
		Coffeen - LH 5, T2120 Lightning Enhancement	C24360			3,142	82,932	122,083	208,158	27,917	236,075	37
	Overhead Line Refurbishment Program Total			-	-	**9,027**	**149,277**	**203,497**	**361,801**	**107,917**	**469,718**	
	Reliability Criteria Compliance	Andover Cap Bank, part of SG075	C24014			2,714	19,406	455,866	477,986	164,134	642,120	39
		Batavia Second 115kV Cap Bank, part of SG077	C31478					23,164	23,164	16,834	39,998	34
		Construct Southwest Station (Line Station), part of SG075	C24016			4,846	1,322	25,922	32,089	4,551	36,640	39
		Construct Southwest Station, part of SG075	C24015			20,842	9,076	205,332	235,250	155,000	390,250	39
		Conversion of #109 to 115kV-part of SG077	C24629			9,868	1,473	37,411	48,752	162,589	211,342	34

		Dunkirk Second Bus Tie- Line, part of SG075	C31460						-	-	-	19
		Dunkirk Second Bus Tie- Station, part of SG075	C31459						-	-	-	19
		Golah work for #109 Conversion - part of SG077	C24631			1,492	484	64,275	66,251	37,013	103,264	34
		Homer Hill 115kV Capacitor Banks, part of SG075	C31457					9,727	9,727	5,279	15,006	28
		Mortimer Work for #109 Conversion - part of SG077	C24630			2,718	270	23,892	26,880	26,108	52,988	34
		Rebuild line #181 and #180 (Station Work), part of SG075	C24019			2,507		39,540	42,047	5,460	47,507	27
		Rebuild line #181 and #180, part of SG075	C24018			26,703	13,568	270,561	310,831	100,000	410,831	27
		Reconductor portions of 54 and 181, part of SG075	C31463						-	-	-	19
		Reconductoring of #171, part of SG075	C24017			5,085	4,583	77,074	86,742	3,213	89,955	39
		Replace HH Ckt #157 Connections, part of SG075	C31458						-	-	-	28
		Replacement of #171 connections, part of SG075	C33884					974	974	3,026	4,000	49
		Second 115kV bus tie at Lockport, part of SG077	C31482					46,850	46,850	10,000	56,850	34
		Upgrade Batavia South 115kV busring, part of SG077	C31479					22,010	22,010	11,056	33,066	28
		Upgrade capabity of L107, part of SG077	C31481					22,628	22,628	27,372	50,000	34
	Reliability Criteria Compliance Total			-	-	76,775	50,181	1,325,226	1,452,182	731,635	2,183,816	
	Reserve	Resreve	CNYX33						-	-	-	49
	Reserve Total								-	-	-	
System Capacity & Performance Total				77,762	952,021	2,000,678	(231,756)	2,878,425	5,677,130	2,306,036	7,983,166	
Non - Infrastructure	Other - Non Infrastructure	Asset Separation strategy	CNYAS87						-	-	-	39
		Flood mitigation	CNYAS46						-	-	-	22
	Other - Non Infrastructure Total								-	-	-	
	Physical Security	Physical Security Strategy	CNYAS86						-	-	-	40
	Physical Security Total										-	
Non - Infrastructure Total											-	
Grand Total				2,914,216	5,906,154	7,729,087	14,009,999	36,753,016	67,312,473	29,393,626	96,706,099	

Date of Request: March 2, 2010
Due Date: March 12, 2010

Request No. VVP-6
NMPC Req. No. NM 170 DPS 100

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Vijay Puran

TO: Infrastructure and Operations Panel

Request:

1. Referring to Exhibit _(IOP-14), Schedule 2, Exhibit 18, Table 2, what is the average age of the steel towers listed as:
   - Visual Grade 1
   - Visual Grade 2
   - Visual Grade 3
   - Visual Grade 4
   - Visual Grade 5
   - Visual Grade 6

2. What is the industry recommended standard for frequency of steel tower painting?

3. What is the industry expected service life of steel towers that: (a) have not been painted; (b) have been occasionally painted; (c) have been regularly painted on an industry recommended schedule?

4. For each of the visual grades listed above, please indicate what percentage of the steel towers (a) have not been painted; (b) have been occasionally painted; (c) have been regularly painted on an industry recommended schedule.

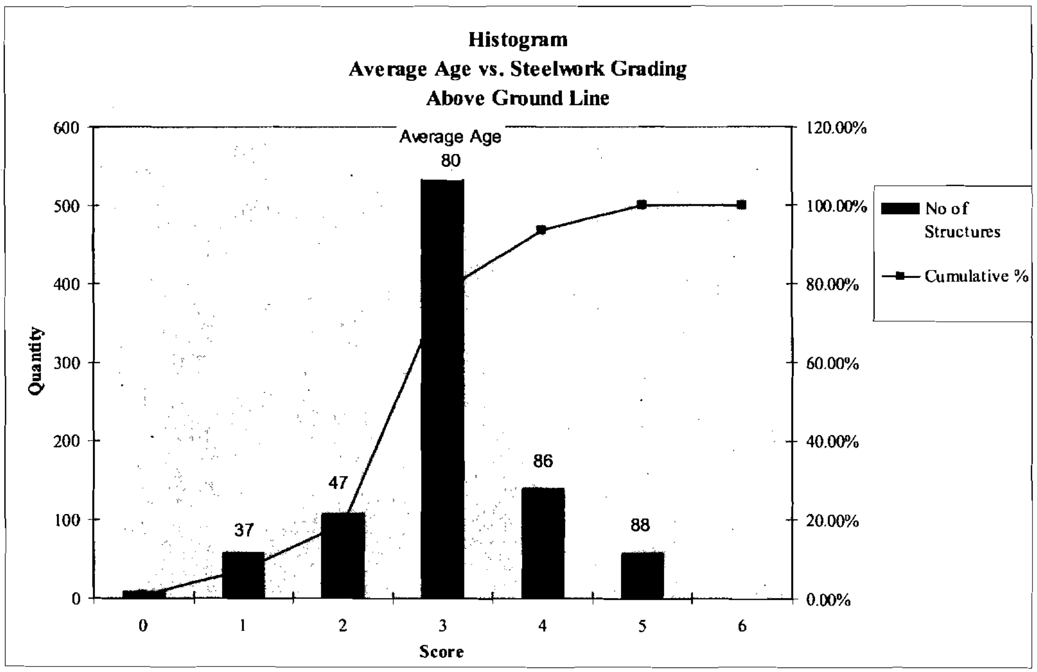
5. On average, what is the last year the steel towers listed in each of the visual grades above was painted?

Form 103

Response:

1. The data in Exhibit (IOP-14), Schedule 2, Exhibit 18, Table 2 come from the Company's Computapole inspection database that houses actual field inspection data. Figure III-2 in Exhibit (IOP-14), Schedule 1, sheet 164 of 315 illustrates our age distribution of steel structures, which comes from our plant accounting records. Plant accounting records typically do not identify individual towers and therefore we can not correlate tower age information with condition information.

During the development of the Tower Painting and Structure Replacement strategy (SG052), average ages obtained from Plant Accounting records from a sample of lines were used with engineering evaluations of tower condition to estimate the condition of the general population of steel towers. The chart below shows the results of this analysis.



Based on this analysis the average age of steel structures in visual grades 3 to 5 would be >80 years.

2. National Grid does not know of a standard industry recommended frequency for painting steel structures. To develop the current painting strategy the Company surveyed other utilities in the Northeast to determine common industry practice. We also reviewed guidance from paint manufacturers that recommended a 20 year cycle, adjusting for environmental factors or evaluations of actual 'paint wear' found through inspection. A summary of the information received from utilities is provided below:

Company	Typical Painting Cycle	Comments
Utility 1	10-20 years	Condition monitoring performed to adjust specific painting cycles, as appropriate
Utility 2	10 year (limited)	Condition based monitoring program by Osmose – work in recent years has primarily been limited to the base of towers (more like the Company's footer maintenance). Painting of top part of transmission towers has generally not been done.
Utility 3	Condition Based	Four years into an 8-9 year process of painting steel structures rated at 3 and 4 on a scale of 1 (the best) to 4 (the worst). A condition assessment was completed approximately 4 years ago.
Utility 4	None	Basically, no tower painting for the last 15-20 years. Evaluating the need for painting as towers are beginning to deteriorate.
Utility 5	20 years	A 5 year cycle is underway with about 1 year left to paint all the transmission structures. A 20 year paint life is anticipated.

The painting strategy was developed by looking into how painting will improve the remaining life of our existing transmission assets. At the time the Steel Tower Strategy (SG018) was written, evidence indicated that use of a properly[1] applied painting system could extend the life of steel structure with rust by 10 years[2]. It is conceivable the lives of some towers could be extended further with additional maintenance painting every 15-20 years. An economic analysis indicated painting towers in Category 4 condition is justified since it would extend the expected remaining life from 10 years to 20 years.

Using this information and other evidence (see reply to question 3, below), the painting strategy recommended implementing a 15-year "interim" painting cycle in New York and the maintenance of a 20-year painting cycle thereafter.

3. The industry expected service life for steel towers that have not been painted is 70 years (with a range of 45 to 80 years). For towers that have been regularly painted the anticipated life of a steel tower would be approximately 85 years[3] (with a range of 65 to

1 Things like the application temperature, thickness, and rain impact the longevity of painting systems.
2 Fuente, D., Simancas, J, and Morcillo, M. (2003). "Effect of variable amounts of rust at the steel/paint interface on the behaviour of anticorrosive paint systems." **Progress in Organic Coating, 46**, pp. 241-249, UK: Elsevier.
3 With little or no pollution

120 years). Regular painting could therefore extend the life of a structure by up to 40 years. The impact of occasional painting is expected to extend the anticipated life of a steel tower less than regular painting (data is not available to estimate by how much). However, a variety of factors such as the amount of atmospheric contaminants and whether or not the structure was originally galvanized, impact how long life can be extended by regular painting.

A July 2003 report by the Woodhouse Partnership Ltd concluded that for UK steel lattice towers, the most economic strategy is to paint at approximately 18 years from the last painting. The report also concluded that the asset life for certain UK types of steel lattice towers can be extended from 60 years to 85 years if the 18 years painting policy is followed. The Northeast US environment is typically less harsh and therefore a 20 year interval is considered appropriate.

4. The Company does not have records to indicate the percentage of the steel towers that (a) have not been painted; (b) have been occasionally painted; (c) have been regularly painted on an industry recommended schedule.

The Company's painting approach is to paint steel structures on a line-by-line basis. In order to do this, the Company looks at a number of factors such as geographical location, outage constraints, refurbishment plans, and inspection condition results. Since FY2005 approximately 3,500 steel transmission structures[4], have been painted . Due to vendor safety issues, the Company's program was suspended for substantial portions of calendar years 2008 and 2009.

5. The Company does not have records to show the last year steel towers in each of the visual grades were painted.

Name of Respondent:	Date of Reply:
Art Peterson	March 12, 2010

4 Partial structure painting is included in this value but as "equivalent" full painting. That is, two structures that are half painted are equivalent to one structure.

Date of Request: March 4, 2010
Due Date: March 15, 2010
DPS 102

Request No. DKS-4
NMPC Req. No. NM 172

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid
Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: David Shahbazian

TO: Revenue Requirement Panel

Request:

1. Book 11, page 21 of the Revenue Requirements Panel testimony references the contract for the Volney Marcy Right of Way agreement. Please provide a complete copy of the contract with all supporting schedules and appendices.

2. Exhibit RRP-10, schedule 8, workpaper 11, sheets 1-12 detail the Company's IS Investment Plan.

   a) Please provide the current copy of the Company's IS Investment Plan, which outlines the Company's IS Strategy for electric and gas operations, including all cost/benefit analysis and supporting workpapers.
   b) Sheets 5 - 8 of workpaper 11 reference the Service Company's return on investment of 5.83%. Please provide the workpapers and supporting schedules to support the calculation of 5.83%.

3. Exhibit RRP-10, schedule 8, workpaper 11, sheet 3, shows monies for a Reserve for Future IS Projects for the years 2012, 2013 and 2014+ of $900k, $900k and $1,799k respectively.

   a) Please provide a full explanation for these reserves, including how the company developed the estimates.
   b) Are these costs included in any of the rate years? If so, please show where the costs are in RY expense and how they are allocated to electric operations.

4. Exhibit RRP-2, Schedule 8, sheets 10-11 of 16 shows total IS rent expense of $7,324,968 for electric operations for the test year. The 2011 electric IS rent forecast is 9,274,450 (increase of 26%). The 2012 electric IS rent

forecast is 14,730,163 (increase of 58%). The 2013 electric IS rent forecast is 19,462,399 (increase of 32%).

a) Please explain these dramatic increases in the rate year IS expenses. In this explanation, include why the Company feels that this elevated level of IS expense is justified and specific examples of how these additional expenses provide benefits to rate payers (e.g., reduced costs, quality of service improvements). Include any cost/benefit analyses or studies that support the Company's justification.

5. Please provide the total Company 36 IS rent expense Actual to Budget performance for the period 2005 – 2009 with breakdown between electric (T&D) and gas operations.

6. Exhibit RRP-2, Schedule 8, sheet 10 lists new IS project cost forecast for 2011. For each of the following, please provide a copy of the actual software license (rental) agreement to support the forecast dollar amount. Please also provide a copy of the INVP detail / data in support of each forecast.

a) Line 21 – Customer Systems Agent Desktop - INVP1656
b) Line 22 – Data Center Rationalization – INVP1088
c) Line 23 – IVR Phase 2 – INVP1306
d) Line 26 – Transformation KPI's – INVP1242

7. Exhibit RRP-2, Schedule 8, sheet 10 shows rate year expense of $1,176k for other projects less than $100k . Please provide a list of these projects and their associated rate year costs. Projects with rate year costs over $25k should be listed separately. Projects less than $25k can be grouped together in one line.

Response:

1. Please see the Volney-Marcy Right of Way operating agreement, as included at Attachment A.

2. a.) Please refer to the IS Investment Plan as included at Attachment B1. For discussion of the Company's IS Strategy, please refer to the testimony of David Lister at Book 3, pages 2 – 8. For cost/benefit discussion and other supporting documentation, please refer to the project summary papers at Attachment B2. Please note that Attachment B2 refers to those individual projects listed in Exhibit___(RRP-2), Schedule 8, Sheets 10 and 11, Lines 18 – 46, excluding Line 24 "Reserve for Future IS Projects – Customer

Systems". Please refer to discussion of this project below at the response to 3a.

b.) Service Company's rate of return on investment of 5.803% is the interest rate due from Service Company to KeySpan Corporation under a long-term intercompany promissory note. This note is the financing vehicle for capital expenditures at the Service Company. A copy of this note is included as Attachment C.

3. a.) The Reserves for Future IS Projects – Customer Systems are put in place to allow for future necessary upgrades or modifications to the customer systems. The upgrades or modifications may be required as a result of many reasons including:

- PSC mandated changes for customer experience or regulatory reporting.
- A system upgrade as a result of the customer system going out of support
- Patches or bug fixes released by vendor

At the time this Plan was developed, the type and number of individual projects was unknown, as the Company will not know what is required in many cases until asked. The value forecast is based on historical expenditure.

Please note the increase from $900k to $1799k is because 2014+ includes 2014 and 2015 expenditure.

b.) The Reserve for Future IS Projects 2012 and 2013 are included in the Rate Year 2012 and 2013 expense at Exhibit___(RRP-2), Schedule 8, Sheet 11, Line 24. However, please note that Exhibit RRP-10, Schedule 8, Workpaper 11, Sheet 1 also shows a related project, Reserve for Future IS Projects 2011. Therefore, the revenue requirement shown at Exhibit___(RRP-2), Schedule 8, Sheets 10 and 11, Line 24 is a summation of the amortization related to these projects, as follows:

Project Description	**RY 2011**	**RY 2012**	**RY 2013**
Reserve for Future IS Projects – Customer Systems 2011	$69,002	$95,423	$89,735
Reserve for Future IS Projects – Customer Systems 2012	$0	$69,002	$95,423
Reserve for Future IS Projects – Customer Systems 2013	$0	$0	$69,002
Reserve for Future IS	$0	$0	$0

Projects – Customer Systems 2014+			
Total - Exhibit___(RRP-2), Schedule 8, Sheets 10 and 11, Line 24	**$69,002**	**$164,425**	**$254,160**

The forecasted project spend of $900k per year was allocated to legacy National Grid companies based on a billing pool allocation of 00229 "O&M Electric & Gas Distribution Companies – NE & NY", under which NiMo Electric receives 44.152%, amortized over five years.

4. a.) Since the KeySpan/National Grid merger, National Grid has been developing a robust IS systems route map to ensure that it delivers improved customer experience and required operational efficiency savings.

The increases in IS rent expenses between the Test Year and 2013 are due to major project expenditures necessary for National Grid to further improve on customer experience and quality of service and also to lay the foundation for process consolidation and improvement going forward to meet required operational efficiency savings.

The main expenditure increase over the four years is on the following pieces of work:

Project Description	**Test Year**	**2011**	**2012**	**2013**
US SAP Back Office	$0	$0	$3,798,446	$5,252,886
Distribution/Outage Management System	$0	$0	$0	$2,534,127
Data Center Rationalization	$0	$452,987	$1,044,266	$1,584,743
Mobile – Electric Distribution Legacy Grid Mobile Expansion	$0	$0	$0	$1,316,336
Customer System Agent Desktop	$0	$687,924	$951,333	$894,626
IVR Phase 2	$0	$603,007	$567,063	$494,145
Transformation KPI	$0	$432,434	$406,657	$354,366
Main Project Expenditure – Total	**$0**	**$2,176,352**	**$6,767,765**	**$12,431,229**

US SAP Back Office

The Primary objective of the Back Office Project is to consolidate onto a single SAP platform, the Finance, Supply Chain and HR functionality now being delivered by the Oracle and PeopleSoft Enterprise Resource Planning Suites. This is National Grid's first step in establishing a strategic, common platform that will improve operations and customer service. The package solution that we plan to deliver will drive a greater level of standardization that will significantly improve quality and efficiency across the supported business functions. The integrated solution will be less complex to maintain, and it will enable the elimination of many manual activities that are performed today. This integrated solution will also provide for better management of National Grid inventory levels thereby lowering costs and enabling us to be more responsive to customer requests by ensuring the right inventory is available at the right time to complete customer work orders in a timely and efficient manner.

Please also refer to the testimony of David Lister at Book 3, Page 12, Line 8 through Page 22, Line 15, as well as the project paper at Attachment B2, Sheets 1 – 17.

Distribution/Outage Management System

The DMS/OMS Project charges are related to benefits achieved with implementation of the new Distribution and Outage Management System (DMS/OMS). Implementations of the systems are needed due to the following:
- There is an existing business need to update the current upstate New York/New England OMS to a vendor supported version.
- There is a business integration need to select a platform for growth to support additional automation on the Distribution Network and Smart Grid.
- The need for integrated OMS/DMS to improve Control Center efficiency by automating manual processes, eliminating paper maps and reducing the duplication of effort required to model the network in disparate systems.
- Implementation of the new systems will result in a single view of the Distribution Network, incorporating all DMS/OMS information (ex; Customer Calls, Real Time Device Status/SCADA Integration, integrated Switch Order Writing and Tracking, Switching and Load Applications, Training Simulator) improving system operators' situational awareness, safety, reliability, and the customer experience. Additionally, the systems will provide the Control Centers with a platform to support Smart Grid initiatives:
- Measure reduction in load and associated cost, improvement in power quality and reliability
- Implement technologies that provide timely energy usage information and automation to encourage and enable customers to reduce load or otherwise alter their consumption patterns.
- Demonstrate how electric distribution grid operating efficiency can be improved measurably by improved monitoring and control.
- Support reductions in critical peak loads with the combination of technology and rate mechanisms. These lower critical peak loads reduce the overall stress on the system. Stress degrades equipment and causes reliability challenges.
- Improve feeder reliability through the implementation of improved monitoring and control of the distribution grid and the integration of automated meter outage

detection and restoration into the existing outage management systems and processes.
- Improve customer satisfaction by providing timely consumption and conservation options, automated load control and improved monitoring and control of the distribution grid.

Please also refer to the testimony of the Infrastructure and Operations Panel (IOP) at Book 26, Page 199, Line 1 through Page 200, Line 13, as well as the project paper at Attachment B2, Sheets 18 – 21.

Data Center Rationalization
National Grid US currently has 4 production data centers in total Henry Clay Blvd (Syracuse NY), Guiderland (Albany, NY,) Hicksville (Long Island, NY) and Melville (Long Island, NY). There are several additional data centers/data halls located throughout the US footprint. The intent of this project is to align with the Corporate strategy and put forth a consolidation plan to achieve a total of two regional data centers within the US footprint. The final configuration will consist of one production data center and one disaster recovery/development data center. Running under the current decentralized data center configuration will not support Corporate initiatives for savings and would increase costs, resources, and infrastructure.

Please also refer to the testimony of David Lister at Book 3, Page 10, Lines 4 – 15, as well as the project paper at Attachment B2, Sheets 38-48.

Mobile – Electric Distribution Legacy Grid Mobile Expansion
This project combines several EDOT mobile related initiatives to provide the business with the technology necessary to attain consistent processes, repeatable results, and improved storms response. The project deliverables include:
1) The ability to dispatch Trouble Orders from PowerOn to the Mobile workforce to allow users to create follow-up work resulting from the original Trouble Order.
2) The functionality required to identify and track the meter work associated with a Service Order (SO), and automate the notification that the meter work has posted and/or completed in CSS,
3) Utilization of mobile technology to capture "As Built" information in the field and provide the workforce real time capability to update asset location information in GIS,
4) Providing all Field Investigators with mobile devices to capture and collect design data in the field (e.g. redlines, photos, docs) and
5) Increasing the Performance Supervisor's presence in the field by providing a true mobile office (hardware) with reliable and effective network access. The technology will facilitate completing administration functions in the field instead of the office and the time in the field will be used to more closely monitor breaks, weather conditions, arrival/departures and to provide coaching to the workforce. The technology provided with this initiative will help drive the following business objectives:

1) Sustainable performance improvements and deliver aggressive efficiency targets,
2) Creating a fundamental operating model shift and platform to support strategic growth,
3) Ensuring organization structure and operating model alignment and
4) Creating a high-performance and results-driven culture.

This initiative provides the hardware and communications the business needs to use GIS and Work Management in a mobile fashion to create simple designs from the field, capture information, etc. It will result in improved customer service and order fulfillment. Additional benefits include:

- Timely and accurate restoration data from the field.
- Timely modeling of restoration.
- Better tracking of Follow-up Work.
- Reduced Radio Chatter and efficiently get outage data to crews.
- Use of real-time interface will allow model to more efficiently be maintained (outage restorations restored/modeled quicker).
- Dispatchers efficiencies gained will support Control Center consolidation.
- Increased field presences of Performance Supervisors
- Maximized productivity, reliability and accountability of the workforce through motivation and coaching
- Increased safety and environmental compliance by reinforcing corporate policies and procedures
- Manage work in a better way with improved access to business applications/tools required for progression of work
- Better response to outages/emergencies with printing capabilities in the field for switching diagrams/ maps / TOAs

Please also refer to the testimony of David Lister at Book 3, Page 200, Line 15 through Page 201, Line 16, as well as the project paper atAttachment B2, Sheets 22-24

Customer Systems Agent Desktop
Agent desktop will improve contact center handling time and first call resolution through the installation of third party automation and integration software over the four existing billing systems (CSS, CAS, CRIS, and Advantage). These improvements will help in meeting Customer & Markets integrations savings targets and also improve overall customer experience for calls into the contact centers.

Please also refer to the testimony of Rudolph L. Wynter at Book 1, Page 12, Line 1 through Page 13, Line 21, as well as the project paper at Attachment B2, Sheets 25-36.

IVR Phase 2

The IVR Replacement Project Phase 2 removes the remaining dialogs that are still being handled on two old and end of life IVR's that are also running on different platforms in Syracuse and Northborough. The project is also expanding capabilities for a couple of existing functions to better self serve our customers. The following functions will be become available on the new IVR in Phase 2:

--Inspection Release
--Customer Survey
--Monthly Meter Reading
--Marketing Opt Out
--Direct Pay Opt Out
--Service Order Maintenance
--NG Supplier Rates
--Service Appointment Outbound calling using Global Connect

Please also refer to the testimony of Rudolph L. Wynter at Book 1, Page 14, Line 1 through Page 15, Line 18, as well as the project paper at Attachment B2, Sheets 49- 57.

Transformation KPI

The Performance Management Electric Distribution Operations Transformation (EDOT) new business process has two goals. First is to establish a performance culture at National Grid and second is to show how an individual's performance has an effect on the Company as a whole. In order to accomplish these goals, the Performance Management group decided to create a hierarchy of scorecards. These scorecards report the performance of the Executive Director of the Distribution organization all the way down to the individual worker. The Performance Management initiative as a whole is a large project with hundreds of reports that calculate variations on approximately 150 metrics to be shown on approximately 400-500 scorecards. KPI Phase I includes the calculation of 13 metrics on approximately 200 scorecards. These metrics reside in 12 data sources. These data sources are incorporated into the data warehouse. All derived scorecards are shown in a hierarchical manner that demonstrates how the performance on each scorecard affects the performance higher up on the hierarchy.

KPI Reporting is a fundamental component of the EDOT program and the ability to track and manage the performance and benefits. These reports are needed to establish a benchmark for National Grid's current performance and to show the increased performance that the EDOT program will deliver. The product of this project allows employees to better manage their work by providing valuable information about subjects important to their role, as well as trending information to show the affects of their decisions over time.

This project is an integral part in realizing the full benefits of the EDOT program.

Please also refer to the testimony of the IOP at Book 26, Page 202, Line 7 through Page 203, Line 8, as well as the project paper at Attachment B2, Sheets 61 - 101.

5. Please refer to Attachment D. Historically, IS rent expenses have not all been recorded in IS cost centers. Some major project rent expense budgets have been recorded within line of business cost centers. The budget rent expense within those cost centers is not detailed by project or asset. The attached ad-hoc report, included as Attachment D, shows the budget rent expenses from FY2006 to FY2009 that the Company believes to relate to IS assets.

   Historically IS has not managed actual capital expenditure to budget based on expected rent expense. The capital investment is managed through reviewing actual project expenditure against an annual capital budget held within the IS department.

6. a.) Please refer to Attachment E1 for the software license agreement pertaining to Customer Systems Agent Desktop. The supporting INVP1656 detail can be found at Attachment B2, Sheets 25 – 36.
   b.) Currently, there are no software license agreements in place related to Datacenter Rationalization. Please refer to the supporting INVP1088 detail at Attachment B2, Sheets 38 – 48.
   c.) All software and hardware related to IVR Phase 2 was purchased as part of IVR Phase 1 which was implemented in 2008. Phase 2 consists of application development work only. Please refer to the supporting INVP1306 detail at Attachment B2, Sheets 49 - 57.
   d.) Please refer to Attachment E2 for the software license agreements pertaining to Transformation KPI's. Please refer to the supporting INVP1242 detail at Attachment B2, Sheets 61 – 101.

7. Please refer to a listing of projects with less than $100,000 in Rate Year 2011 expense as included at Attachment F.

<u>Name of Respondent:</u>
Melissa Little/Avron Segal

<u>Date of Reply:</u>
March 17, 2010

Form 103

INVP 1088

CTA Funded Sheets 38 & 39
1 of 2

Confidential

Ref. No. XXX

CAPEX / OPEX IS Investment Proposal – Summary
US Data Centre Rationalisation
CTO, Form of Control - Shared, Project No. [xxx]
(A sanction paper by Chris Granata – 03/38/2008)

Description

A number of strategic projects have been identified to support the integration of National Grid US and KeySpan. This paper addresses the US Data Centre Rationalisation project – expected to deliver significant RTB reductions and one-off cost reductions. Project is funded from CTA budget.

The costs for this project will be allocated to:
- Gas Distribution - 37%
- Electric Distribution & Generation – 57%
- Electric Transmission – 5%
- Business Development & Non-Regulated – 1%

This investment proposal seeks sanction of funds for:
- Detailed requirements, analysis, design and planning
- Procurement of specialist integration support
- Engagement of specialist external support necessary to deliver as above
- Perform initial expansion activities at Henry Clay Blvd data center (Syracuse, NY) supporting integration within the data center environment

At the end of this stage our goal is to seek sanction for the next Phase of the project. We will assess if we require full sanction for the total project cost or for a portion of the total project cost.

Category: NPV
Risk score: 45, Primary Driver – loss of financial benefit
Project Classification: High Region: US

Finance

Sanction Cost $3.5M
(The money for this sanction, as well as the entire project cost, has been identified as a key integration project and is being funded through CTA)

Approximate Distribution:
Strategy:
- Labor - $500K (Internal Labor – PM, Enterprise Operations Support, etc)
- Consultants - $500K

Initial Expansion Activities - $2.5M

This work is the first phase of expansion of HCB to enable the future closure of Melville and establishment of Production services in Henry Clay Blvd. Activities for expansion include:
- Replace Floor/Ceiling Tiles
- Modify Overhead Lighting
- Provide Cable Management
- General Construction (Remove/Add walls, Paint, etc)

- Add CRAC Units (Computer Room Air Conditioning)
- Add PDUs (Power Distribution Units)
- Analyze Generator Capacity
- Contractor Costs

Overall indicative cost (Prospective Gross Sanction Value): $35M

Project included in approved Business Plan? Yes - INVP1088

Other financial issues

This is a KSE integration-related investment which was included within the original Cost To Achieve (CTA)

Resources

Availability of internal resources to deliver project:	Green
Availability of external resources to deliver project:	Green
Operational impact on network system:	N/A

Key issues

- The assumptions we are working under are that Henry Clay Blvd (Syracuse, NY) and Hicksville (Long Island, NY) will be the National Grid strategic data center locations. Below are the known risks:
- Properties is in the process of posting for a Project Manager to oversee the Upstate New York regional site consolidation. There appear to be many organizations, aside from IS, that require space at Henry Clay Blvd. Properties is unable to move forward until all areas provide their requirements and a master space plan is developed.
    - Risk: Delays in Properties selection could impact progress and ultimately impact available CTA funds
    - The value of money at risk is less than the CTA dollars we would lose if we delay the project at this point
- Properties has not announced the strategic Long Island facility. We are working under the assumption that Hicksville will be named the strategic site for Long Island. Properties has not given us any indication that Hicksville will or will not be the strategic Long Island facility.
    - Risk: Delays in Properties selection could impact progress and ultimately impact available CTA funds
    - The value of money at risk is less than the CTA dollars we would lose if we delay the project at this point
- LIPA - Once Properties identifies the strategic site on Long Island we will communicate the final data center site locations to LIPA. We will need to explain to LIPA the infrastructure that will be implemented measures that will be in place to.

Key milestones

- Scheme Paper Approval - April 2008
- Establish Project Review Board – April 2008
- Assess Current Strategy – May 2008
- Assess Property Risk – May 2008
- Create Detailed Design Documents – Sept 2008

CTA Funded INVP 1092
Sheets 153 & 154
1 of 2

Confidential

Ref. No. XXX

IS Investment Proposal – Summary
OneNet Keyspan Project Implementation – Brian Kelly, Sponsor
Information Services CTO, Shared, Project No. INVP1092
A sanction paper by Bob Coffey-September 2008

Description

This investment proposal seeks sanction of funds for the OneNet Keyspan Project. The project is an Integration Project that will migrate Keyspan employees to the National Grid desktop, fileserver, Email and Collaboration standard configurations Funds have been approved for the initial Requirements & Design stages of the project. At this time full sanctioning of the total project costs for the Implementation stage are sought as the Requirements and Design phase nears completion.

Category: NPV
Risk score: 45, NPV
Project Classification: Medium Region: US

Finance

The following funds have been sanctioned to date for the OneNet Keyspan Project:

January 18, 2008 - $436K Capex approved for early Email Migration to support the Keyspan re-branding effort.
April 3, 2008 - $1,980K ($909K Opex, $1071 Capex) approved the for Requirements and Design Stage

The funds that are required for sanctioning on this request to complete the project:

$8,186K ($5,478K Opex, $2,708K Capex)

Total Project Cost - $10,602K ($6,387K Opex, $4,215K Capex)

This project is CTA related to the Keyspan Merger. The CTA portion of the Opex Cost is $3964K. The form of control funding will be split by Keyspan LOB headcount.

The breakdown of the $8186K is as follows;
Internal Labor - $1811K
Software – $4563K
Hardware - $162K
Contract Labor - $1370K
Employee Expense $100K
Risk – $180K

Cost volatility: NA

Confidential Ref. No. XXX

Probability that project cost will exceed tolerance: NA
Project included in approved Business Plan? Yes, INVP1092, IS Global Investment plan v1 final
Other financial issues:
This is a KSE integration-related investment which was included within the original Cost To Achieve (CTA)

Resources

Availability of internal resources to deliver project:	[Green]
Availability of external resources to deliver project:	[Green]
Operational impact on network system:	[Green]

- **Key issues**
- Delivery of Hardware and Software under global purchasing agreements to meet 1/9/08 deployment start.
-

Key milestones
- Requirements and Design Completion – July 31, 2008
- Submit Plan for full funding – July , 2008
- Pilot migration – August, 2008
- Deployment – September 1, 2008 – March 31,2009
- Completion – March 31, 2009
- Project closure – May 31, 2009

Climate change

Contribution to National Grid's 2050 60% emissions reduction target:	Neutral
Impact on adaptability of network for future climate change:	Neutral
Are financial incentives (e.g. carbon credits) available?	No

Prior sanctioning history:
- April 3, 2008 – IS Project Review Meeting – Requirements and Design
- January 18, 2008 – IS Project Review Meeting – Email Support of Rebranding

Recommendations
The Sanctioning Authority is invited to:
(a) APPROVE the investment of $8186k which includes a risk margin of $180K by July 31, 2008
(b) NOTE that Brian Kelly is the Project Sponsor
(c) NOTE that Bob Coffey is the Project Manager and has the approved financial delegation to deliver the project

IS Finance

Date of Request: March 4, 2010
Due Date: April 2, 2010

Request No. MJR-1 SUPP A
NMPC Req. No. NM 173 DPS 103

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Michael Rieder

TO: Infrastructure and Operations Panel

Request:

3. For each project listed in Exhibit IOP-1, Schedule 8, identify the strategy paper and sanction paper for each project, linking each Project Number to the title and date of both the associated strategy paper and sanction paper. Provide the requested information in Excel format in the same format and project sequence as shown in Exhibit IOP-1, Schedule 8

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4. Provide each strategy paper and sanction paper identified in No. 3.

5. If a project does not have a strategy paper or sanction paper, indicate that it does not and provide relevant studies and documents that fully describe, justify, and support the project's need, cost, and schedule.

Response:
SUPP-A (Transmission, non-confidential)

3. Attachment 1 (MJR-1 SUPP-A_Tx) identifies strategy papers, sanction papers, studies, and other documentation, along with corresponding dates, for projects listed in Exhibit __ (IOP-1), Schedule 8, for Transmission projects by investment category (i.e., Statutory/Regulatory, Damage/Failure, System Capacity and Performance, Asset Condition and Non-Infrastructure).

4. Non-confidential strategy papers, sanction papers, and relevant studies listed in Attachment 1 are provided. Due to their number and size, these files are being provided to the requester on diskette. Copies will also be provided to other parties upon request. The Company will be providing copies of the indicated confidential strategy papers, sanction papers, and relevant studies in accordance with a forthcoming request for protective treatment.

5. See responses to 3 and 4, above.

Name of Respondent:
Antoinette Stores
Legal Department

Date of Reply:
April 14, 2010

Date of Request: March 4, 2010
Due Date: April 2, 2010

Request No. MJR-1 SUPP A-2
NMPC Req. No. NM 173 DPS 103

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Michael Rieder

TO: Infrastructure and Operations Panel

Request:

3. For each project listed in Exhibit IOP-1, Schedule 8, identify the strategy paper and sanction paper for each project, linking each Project Number to the title and date of both the associated strategy paper and sanction paper. Provide the requested information in Excel format in the same format and project sequence as shown in Exhibit IOP-1, Schedule 8.

4. Provide each strategy paper and sanction paper identified in No. 3.

5. If a project does not have a strategy paper or sanction paper, indicate that it does not and provide relevant studies and documents that fully describe, justify, and support the project's need, cost, and schedule.

Response:
SUPP-A-2 (Transmission, non-confidential)

3, 4, & 5. Attached hereto are Strategy Papers:

1. SG029 & SG029 v2c
2. SG018 v1
3. SG009
4. SG075

These Strategy Papers were not reflected in the spreadsheet submitted with the response to IR MJR-1-SUPP-A, nor were the papers included on the diskette that was provided with that submission.

Strategy Papers SG029 and SG029 v2c relate to Project C31141, which is a project in the Transmission, Statutory Regulatory investment category. For Project C31141, SG029 v3 was included among the Transmission, Statutory Regulatory, non-confidential documents included with the response to IR MJR-1-SUPP-A submitted on April 14, 2010. SG029 and SG029 v2c were inadvertently omitted assuming that SG029 v3 replaces these original papers. After discovering that this is not the case, SG029 and SG029 v2c are submitted here.

Strategy Paper SG018 v1 relates to Project C25539, which is a project under the Transmission, Damage Failure investment category. For Project C25539, SG018 v2 was included among the Transmission, Damage Failure, non-confidential documents included with the response to IR MJR-1-SUPP-A. SG018 v1 was inadvertently omitted assuming that SG018 v2 replaces SG018 v1. After discovering that this is not the case, SG018 v1 is now being submitted.

Strategy Paper SG009 relates to Project C11640 under the Transmission, Damage Failure investment category. For Project C11640, SG009 v2a was included among the Transmission, Damage Failure, non-confidential documents included with the response to IR MJR-1-SUPP-A. SG009 was inadvertently omitted assuming that SG009 v2a replaces SG009. After discovering that this is not the case, SG009 is now being submitted.

Strategy Paper SG075 relates to the Overhead Line Refurbishment Program under the Transmission, System Capacity and Performance investment category. SG075 v2 was included among the Transmission, System Capacity and Performance, non-confidential documents included within the response to IR MJR-1-SUPP-A. SG075 was inadvertently omitted assuming that SG075 v2 replaces SG075. After discovering that this is not the case, SG075 is submitted here.

In addition to the aforementioned papers, the Company submits a revised spreadsheet reflecting the addition of these papers.

<u>Name of Respondent:</u>
Antoinette Stores
Legal Department

<u>Date of Reply:</u>
May 19, 2010

Response IR MJR-1 Transmission--Non-Infrastucture

Network Segment	Program	Project Number	Project Name	Project Status	Sanction paper	Strategy paper	Approved Sanction/Strategy Date	Confidential (Y/N)	Risk Score	FY11	FY12	FY13	FY14	FY11-14
Transmission	Other - Non Infrastructure	CNYAS87	Asset Separation strategy	N/A	N/A	N/A	N/A	n/a	39	0	0	0	0.1	0.1
		CNYAS46	Flood mitigation	N/A	N/A	Please refer to Request No. AJR-1 - NMPC Request No. NM 45 DPS 42	N/A	No	22	0	0	2	1	3
	Other - Non Infrastructure Total									**0**	**0**	**2**	**1.1**	**3.1**
	Physical Security	CNYAS86	Physical Security Strategy	N/A	N/A	SG132	02/25/2010	Yes	40	0.1	6	3	0	9.1
	Physical Security Total									**0.1**	**6**	**3**	**0**	**9.1**
Transmission Total										**0.1**	**6**	**5**	**1.1**	**12.2**
Total Non-Infrastructure										**3.3**	**11.4**	**10.6**	**6.9**	**32.2**

3. For each project listed in Exhibit IOP-1, Schedule 8, identify the strategy paper and sanction paper for each project, linking each Project Number to the title and date of both the associated strategy paper and sanction paper. Provide the requested information in Excel format in the same format and project sequence as shown in Exhibit IOP-1, Schedule 8.

4. Provide each strategy paper and sanction paper identified in No. 3.

5. If a project does not have a strategy paper or sanction paper, indicate that it does not and provide relevant studies and documents that fully describe, justify, and support the project's need, cost, and

Network Segment	Program	Project Number	Project Name	Project Status	Sanction paper	Strategy paper	Approved Sanction / Strategy Date	Confidential (Y/N)	Risk Score	FY11	FY12	FY13	FY14	FY11-14
Transmission	Clay Station Rebuild	C32539	Clay Station Line Project	Open	N/A	SG095	July 21, 2008	Yes	49	0.1	2	2	0	4.1
	Clay Station Rebuild Total									**0.1**	**2**	**2**	**0**	**4.1**
	Clearance Strategy	C31141	Oswego Lafayette 17, T2420 CCR	Open	N/A	SG029v3	April 22, 2009	No	33	0.5	0	0	0	0.5
		C03256	Transmission Tower Clearances	Open	N/A	SG029v3	April 22, 2009	No	40	1	15	15	15	46
	Clearance Strategy Total									**1.5**	**15**	**15**	**15**	**46.5**
	Digital Fault Recorder Strategy	C03726	Digital Fault Recorder Strategy	Open	AMIC07133 AMIC07121 AMIC0775 AMIC0749 NTSC0659 NTSC0658 NTSC0569 NTSC 0555 AMIC0983 AMIC0986 AMIC0832 AMIC09104	SG010v2	August 24, 2007 July 23, 2007 April 25, 2007 August 23, 2006 July 24, 2006 July 21, 2005 June 30, 2005 December 18, 2009 December 18, 2009 February 14, 2008 March 18, 2008 January 25, 2010	Yes	49	1.1	0	0	0	1.1
		C29487	Repl DFR at Non-BPS Stations	Open	N/A	N/A	N/A	N/A	27	0	0	0	0	0
	Digital Fault Recorder Strategy Total									**1.1**	**0**	**0**	**0**	**1.1**
	Generation	CNYX63	Alabama Ledge Wind-Loop in, Loop-out	N/A	N/A	Study Attached	February 16, 2007	Yes	49	0.2	0.2	0	0	0.4
		CNYX63R	Alabama Ledge Wind-Loop in, Loop-out Reimbursable portion	N/A	N/A	Study Attached	Ferbraury 16, 2007	Yes	49	-0.2	-0.4	0	0	-0.5
		CNYX64	Alabama Ledge Wind-RTU/Metering/Relay upgrades	N/A	N/A	Study Attached	Ferbraury 16, 2007	Yes	49	1	0.7	0	0	1.6
		CNYX64R	Alabama Ledge Wind-RTU/Metering/Relay upgrades-Reimbursable portion	N/A	N/A	Study Attached	Ferbraury 16, 2007	Yes	49	-1	-0.7	0	0	-1.6
		CNYX01	Athens Generation Expansion –Permanent Line	N/A	N/A	N/A	N/A	N/A	1	6	10.4	25.5	26.1	68
		CNYX01R	Athens Generation Expansion –Permanent Line Reimbursable	N/A	N/A	N/A	N/A	N/A	1	-6	-10.4	-25.5	-26.1	-68
		CNYX02	Athens Generation Expansion –Permanent Sub	N/A	N/A	N/A	N/A	N/A	1	0	0	0.5	3.4	3.9
		CNYX02R	Athens Generation Expansion –Permanent Sub Reimbursable	N/A	N/A	N/A	N/A	N/A	1	0	0	-0.5	-3.4	-3.9
		C23413	BEDCO Substation Work	Open	AMIC07164	N/A	December 21, 2007	Yes	49	0.1	0	0	0	0.1
		CNYX60	Cape Vincent Wind-RTU/Metering/Relay upgrades	N/A	N/A	N/A	N/A	N/A	49	0.1	2.7	0	0	2.8
		CNYX60R	Cape Vincent Wind-RTU/Metering/Relay upgrades-Reimbursable	N/A	N/A	N/A	N/A	N/A	49	-0.1	-2.7	0	0	-2.8
		CNYX70	Clayton Wind-Loop in, Loop-out	N/A	N/A	Study Attached	April 30, 2007	Yes	49	0.4	2	0	0	2.4
		CNYX70R	Clayton Wind-Loop in, Loop-out Reimbursable portion	N/A	N/A	Study Attached	April 30, 2007	Yes	49	-0.4	-2	0	0	-2.4
		CNYX71	Clayton Wind-RTU/Metering/Relay upgrades	N/A	N/A	Study Attached	April 30, 2007	Yes	49	0.3	1	0	0	1.3
		CNYX71R	Clayton Wind-RTU/Metering/Relay upgrades-Reimbursable portion	N/A	N/A	Study Attached	April 30, 2007	Yes	49	-0.3	-1	0	0	-1.3
		C29583	Fairfield Wind Farm Interconnection	Open	AMIC07178	N/A	July 9,2008	Yes	49	0.8	0	0	0	0.8
		C29583R	Fairfield Wind Farm Interconnection – Reimbursbale Portion	Open	AMIC07178	N/A	July 9,2008	Yes	49	-0.8	0	0	0	-0.8
		C29782	Fairfield Wind-loop in loop out	Open	N/A	N/A	N/A	N/A	49	1	0	0	0	1

		C29782R	Fairfield Wind-loop in loop out(reimb)	Open	N/A	N/A	N/A	N/A	49	-1	0	0	0	-1
		CNYX68	Green Power-Cody Rd-loop in,loop out	N/A	AMIC0961	N/A	August 2, 2009	Yes	49	0.5	0	0	0	0.5
		CNYX68R	Green Power-Cody Rd-loop in,loop out	N/A	AMIC0961	N/A	August 2, 2009	Yes	49	-0.5	0	0	0	-0.5
		CNYX69	Green Power-Cody Rd-RTU,metering	N/A	AMIC0961	N/A	August 2, 2009	Yes	49	1	0	0	0	1
		CNYX69R	Green Power-Cody Rd-RTU,metering	N/A	AMIC0961	N/A	August 2, 2009	Yes	49	-1	0	0	0	-1
		CNYPL3	Inghams SPS updates	N/A	N/A	N/A	N/A	N/A	40	0.1	0.1	0.1	0.1	0.4
		CNYX53	Jordanville Wind-Loop in,Loop out	N/A	AMIC 0875	N/A	November 10, 2008	Yes	49	0.2	0.5	0	0	0.7
		CNYX53R	Jordanville Wind-Loop in,Loop out Reimbursable Portion	N/A	AMIC 0875	N/A	November 10, 2008	Yes	49	-0.2	-0.5	0	0	-0.7
		CNYX54	Jordanville Wind-RTU/metering/Relay upgrades	N/A	AMIC 0875	N/A	November 10, 2008	Yes	49	0.2	2.3	0	0	2.5
		CNYX54R	Jordanville Wind-RTU/metering/Relay upgrades Reimbursable Portion	N/A	AMIC 0875	N/A	November 10, 2008	Yes	49	-0.2	-2.3	0	0	-2.5
		CNYX65	New Grange Wind-Loop in, Loop-out	N/A	N/A	Study Attached	Ferbraury 14, 2008	Yes	49	0.4	0.4	0	0	0.8
		CNYX65R	New Grange Wind-Loop in, Loop-out Reimburseable portion	N/A	N/A	Study Attached	Ferbraury 14, 2008	Yes	49	-0.4	-0.4	0	0	-0.8
		CNYX66	New Grange Wind-RTU/Metering/Relay upgrades	N/A	N/A	Study Attached	Ferbraury 14, 2008	Yes	49	1.3	1.1	0	0	2.4
		CNYX66R	New Grange Wind-RTU/Metering/Relay upgrades-Reimbursable portion	N/A	N/A	Study Attached	Ferbraury 14, 2008	Yes	49	-1.3	-1.1	0	0	-2.4
		C27745	Noble Bliss 1 – New Arcade Tap	Open	AMIC07152	N/A	October 17, 2007	Yes	49	0.3	0	0	0	0.3
		C27745R	Noble Bliss 1 – New Arcade Tap – Reimbursable Portion	Open	AMIC07152	N/A	October 17, 2007	Yes	49	-0.3	0	0	0	-0.3
		C24981	Noble Bliss Wind Farm	Open	AMIC07152	N/A	October 17, 2007	Yes	35	0.1	0	0	0	0.1
		C24981R	Noble Bliss Wind Farm – Reimbursbale Portion	Open	AMIC07152	N/A	October 17, 2007	Yes	49	-0.1	0	0	0	-0.1
		CNYX67	Sherman Island Uprate-RTU/Metering/Relay upgrades	N/A	AMIC08120	N/A	January 19, 2009	Yes	49	0.8	0	0	0	0.8
		CNYX67R	Sherman Island Uprate-RTU/Metering/Relay upgrades-Reimbursable portion	N/A	AMIC08120	N/A	January 19, 2009	Yes	49	-0.8	0	0	0	-0.8
		CNYX55	St Lawrence Wind-Loop in, Loop-out	N/A	AMIC0964	N/A	August 21, 2009	Yes	49	0.1	0.9	0	0	1
		CNYX55R	St Lawrence Wind-Loop in, Loop-out Reimburseable Portion	N/A	AMIC0964	N/A	August 21, 2009	Yes	49	-0.1	-0.9	0	0	-1
		CNYX56	St Lawrence Wind-RTU/Metering/Relay upgrades	N/A	AMIC0964	N/A	August 21, 2009	Yes	49	0.6	1.6	0	0	2.2
		CNYX56R	St Lawrence Wind-RTU/Metering/Relay upgrades-Reimbursable Portion	N/A	AMIC0964	N/A	August 21, 2009	Yes	49	-0.6	-1.6	0	0	-2.2
		CNYX49	WestHill Wind –Loop in-loop out	N/A	AMIC07179	N/A	January 9, 2008	Yes	49	0.4	0	0	0	0.4
		CNYX49R	WestHill Wind –Loop in-loop out Reimbursable Portion	N/A	AMIC07179	N/A	January 9, 2008	Yes	49	-0.4	0	0	0	-0.4
		CNYX50	WestHill Wind –RTU/metering	N/A	AMIC07179	N/A	January 9, 2008	Yes	49	0.6	0	0	0	0.6
		CNYX50R	WestHill Wind-RTU/metering Reimbursable Portion	N/A	AMIC07179	N/A	January 9, 2008	Yes	49	-0.6	0	0	0	-0.6
			Generation Total							**0.1**	**0**	**0.1**	**0.1**	**0.3**
	Load	CNYPL8	New Distribution for Load Growth	Reserve	Reserve	Reserve	Reserve	Reserve	30	0.2	2	2	2	6.2
		C27423	Reynolds Road 115-13.2Kv Second Bank	Open	AMIC08104	N/A	November 4, 2008	Yes	35	0.7	0	0	0	0.7
		C29824	Unifax	Open	N/A	SG101	September 11, 2008	Yes	49	0.1	0.2	0	0	0.3
		C29824R	Unifax –Reimbursbale Portion	Open	N/A	SG101	September 11, 2008	Yes	49	-0.1	-0.2	0	0	-0.3
			Load Total							**0.9**	**2**	**2**	**2**	**6.9**
	Luther Forest	C22738	Luther Forest Relay and Malta Sub work	Open	AMIC0958 - TIC0916	SG060, SG097	October 21, 2009	Partial	49	3.4	4.8	0	0	8.2
			Luther Forest Total							**3.4**	**4.8**	**0**	**0**	**8.2**
	Northeast Region Reinforcement	CNYX39	Design/Build NERR	N/A	N/A	SG097	February 17, 2009	Yes	36	0.5	5	13.4	11.9	30.8
		C18250	Re-conductor Rotterdam 1&2 Lines – Part of NERR	Open	AMIC08110 - TIC0817	SG097	December 12, 2008 - February 17, 2009	Yes	49	3	0	0	0	3
		CNYX39A	Rotterdam Banks – Part of NERR	N/A	N/A	SG097	February 17, 2009	Yes	36	0	0	1.3	17.7	19
		C31418	Spier Rotterdam Line#3 – Part of NERR	Open	N/A	SG097	February 17, 2009	Yes	49	1.6	9.7	25.3	8.6	45.1
		C31326	Turner Rd new 230-115kV Station – Part of NERR	Open	N/A	SG097	February 17, 2009	Yes	49	2	25	17.3	0.2	44.4
		C31419	Turner Road New Line Taps – Part of NERR	Open	N/A	SG097	February 17, 2009	Yes	49	0.3	1.5	7.8	0.1	9.6
			Northeast Region Reinforcement Total							**7.3**	**41.2**	**65**	**38.5**	**151.9**

	Other Statutory/ Regulatory	C29483	Repl 23 meters Interconnect/ NYISO	Open	N/A	SG127	January 8, 2010	No	49	0.8	2	1.8	1.4	5.9
		C32551	Various Station – Range Operations	Open	N/A	Study Attached	September 7, 2007	Yes	49	0.1	0	0	0	0.1
	Other Statutory/Regulatory Total									**0.8**	**2**	**1.8**	**1.4**	**5.9**
	RTU Strategy	C03772	RTU Replacements NERC, EMS, Obsolescence	Open	NTSC0585 NTSC0655 AMIC07129 AMIC0850 AMIC0855 AMIC08119 AMIC09106 AMIC0938 AMIC0970	SG002v2	May 27, 2009 August 18, 2005 July 17, 2006 September 10, 2007 June 2, 2008 July 22, 2008 December 22, 2008 February 5, 2010 October 1, 2009	Mixed	49	1.5	2	1.4	0	4.9
	RTU Strategy Total									**1.5**	**2**	**1.4**	**0**	**4.9**
	Station Upgrades	C28686	Porter sub	Open	N/A	SG094	April 22, 2009	Yes	40	0.1	12	12	0	24.1
		C28705	Clay Sub	Open	N/A	SG095	July 21, 2008	Yes	49	9.8	8	11	0	28.8
	Station Upgrades Total									**9.9**	**20**	**23**	**0**	**52.9**
	Reserve	CNYX32	Reserve	Reserve	Reserve	Reserve	Reserve	Reserve	49	-3.2	-10.7	-11.2	-6.6	-31.7
	Reserve Total									**-3.2**	**-10.7**	**-11.2**	**-6.6**	**-31.7**
Transmission Total										**23.3**	**78.2**	**99**	**50.4**	**250.9**
Total Statutory/Regulatory										**156.6**	**230.8**	**255.5**	**207.6**	**850.4**

Network Segment	Program	Project Number	Project Name	Project Status	Sanction paper	Strategy paper	Approved Sanction/Strategy Date	Confidential (Y/N)	Risk Score	FY11	FY12	FY13	FY14	FY11-14
Transmission	NY Inspection Projects	C26923	NY Inspection Projects - Capital	Open	AMIC08116	N/A	February 25, 2009	No	49	0.4	1	1	3	5.4
	NY Inspection Projects Total									**0.4**	**1**	**1**	**3**	**5.4**
	Other Damage/ Failure	C29320	Curtis St- Repl LN10 &13 Relays	Open	N/A	PIW - TS0420081267	Apil1 11, 2008	No	26	0	0.2	0	0	0.2
		C28324	Geres Lock Sub- Repl 14 115kV Disc	Open	N/A	PIW - S0120080229	Jan. 1, 2008	No	19	0.3	0	0	0	0.3
		C32504	Getzville-Sta60 Repl Cntrl Hse Roof	Open	N/A	PIW - TS120091487	N/A	No	35	0	0	0	0	0
		C28303	Kensington Sub Repl TB#4 & 5 LTC Control	Open	AMIC09111	N/A	December 18, 2009	No	28	0	0	0	0	0
		C32964	Leeds - PV 92 T5330 Str 361	Open	N/A	N/A	N/A	N/A	40	0	0.5	0	0	0.5
		C20546	New Gardenville- Repl 230kV Bi	Open	N/A	N/A	N/A	N.A	27	0.1	0	0	0	0.1
		C22391	Oneida - TB#3 Failure	Open	AMIC0849	N/A	July 22, 2008	No	49	0.8	0	0	0	0.8
		C28964	Oneida Sub- Replace LTG & React Ckts	Open	N/A	PIW-128-2007	6/29/2007	No	16	0.2	0	0	0	0.2
		C32596	Porter Sub - Repl. Barre ...outr & Auto	Open	N/A	PIW - 9-2008 & DS1020081447	N/A	No	35	0	0	0	0	0
		C31660	Replace Damaged Insulators	Open	N/A	N/A	N/A	N./A	40	0.4	0	0	0	0.4
		C18952	S. Oswego R/R LN1 Tone Package	Open	N/A	N/A	N/A	N/A	33	0.2	0	0	0	0.2
		C03278	Transmission Line Replacements Budgetary	Open	AMIC0744 AMIC0782 AMIC07116 AMIC07125	Reserve	March 16, 2007 May 14, 2007 July 5, 2007 July 20, 2007 April 8,	No	49	0.2	0.2	0.2	0.2	0.8
		C03792	Transmission Station Failures - Budgetary	Open	Reserve	Reserve	Reserve	Reserve	49	1	1.4	2.7	3.1	8.2
		C03481	Transmission Storm Budgetary Reserve	Open	AMIC0797 AMIC07107 AMIC0997 AMIC07142	N/A	June 7, 2007 May 31, 2007 Oct. 23, 2009 Aug. 27, 2007 April 29, 2009	Yes, Yes, No, No, No	49	0.3	0.3	0.3	0.3	1

		C13622	Transmission UG C Budgetary Reserve - Co	Open	Reserve	Reserve	Reserve	Reserve	49	0	0	0	0	0.1
		C26144	Yahnundasis - Repl 18 & 28 Switches	Open	AMIC08125	N/A	February 2, 2009	Yes	28	0.4	0	0	0	0.4
	Other Damage/Failure Total									**3.8**	**2.5**	**3.2**	**3.6**	**13.2**
	Steel Tower Strategy	C25539	Visual Grade 6 Tower Replacements	Open	N/A	SG018v2	December 15, 2005	No	40	0.1	0.1	0.1	0.1	0.5
	Steel Tower Strategy Total									**0.1**	**0.1**	**0.1**	**0.1**	**0.5**
	Wood Pole Strategy	C11640	Wood Pole Management - NY	Open	AMIC0898 AMIC08103 AMIC0994	SG009v2a	October 22, 2008 October 28, 2008 November 25, 2009	No	43	1.8	1.5	1.6	3	7.9
	Wood Pole Strategy Total									**1.8**	**1.5**	**1.6**	**3**	**7.9**
Transmission Total										**6.1**	**5.2**	**5.9**	**9.7**	**26.9**
Total Damage/Failure										**30.6**	**31.1**	**32.7**	**37.4**	**131.9**

Network Segment	Program	Project Number	Project Name	Project Status	Sanction paper	Strategy paper	Approved Sanction/Strategy Date	Confidential (Y/N)	Risk Score	FY11	FY12	FY13	FY14	FY11-14
Transmission	Frontier Region	C11496	Refurbishment of Huntley 230kV Station	Open	AMIC 0814 - TC0802	SG042v2	March 28, 2008 September 26, 2006	Yes	22	0	0	0.1	2.3	2.4
		C11494	Tonawanda Station - Line Work	Open	AMIC 0814 - TC0802	SG042v2	March 28, 2008 September 26, 2006	Yes	49	6.2	23	3.7	0.4	33.2
		C11495	Tonawanda Station - Station Work	Open	NTSC0618 NTSC06131 AMIC 0814-TC0802	SG042v2	May 16, 2006 February 10, 2007 March 28, 2008 September 26, 2006	Yes	49	23.1	31.3	8.5	3	65.9
	Frontier Region Total									**29.3**	**54.3**	**12.3**	**5.7**	**101.6**
	Load	C30744	Frankhauser New Station - T Line Work	Open	N/A	SG107	February 5, 2010	No	41	0.2	0.4	0	0	0.6
		C30765	Install Second Transformer - Inman Rd	Open	N/A	SG140	March 4, 2010	No	39	0.9	0.9	0	0	1.7
		C30824	Replace TB#1 Everett Rd	Open	N/A	N/A	N/A	n/a	30	1	0.6	0	0	1.6
	Load Total									**2.1**	**1.8**	**0**	**0**	**3.9**
	Other System Capacity & Performance	C22071	Albany Steam - Add 2nd Station svc	Open	N/A	N/A	N/A	n/a	16	0.2	0.2	0	0	0.4
		C33744	BlackRiver-LHHX5-2 LB Attachment	Open	N/A	SG131	December 18, 2009	No	49	0	0.1	0	0	0.1
		C33742	BlackRiver-Taylorville#2 New Switch	Open	N/A	N/A	N/A	n/a	43	0	0.3	0	0	0.3
		CNYPL4	Boonville-Rome #4 Reconductorin	N/A	N/A	N/A	N/A	n/a	40	0	0	0.1	5	5.1
		C21353	Dewitt 345kV Breaker Install	Open	N/A	SG066	June 22, 2007	Yes	6	0	0.8	0.6	0	1.5
		C32337	East Watertown 115 Mobile tap	Open	N/A	SG121	October 8, 2009	No	49	0	0.1	0.2	0	0.3
		CNYPL7	Eastern NY 115kV Capacitor	N/A	N/A	N/A	N/A	n/a	35	0	0	0.1	2	2.1
		C28384	Farmington 11 Line Rearrangemen	Open	N/A	SG089	May 6, 2008	No	49	1.5	0	0	0	1.5

		C28384R	Farmington 11 Line Rearrangement - Reimb	Open	N/A	SG089	May 6, 2008	No	49	-1.5	0	0	0	-1.5
		CNYPL14	Fourth Elm 230-23kV Bank (N-1-1)	N/A	N/A	N/A	N/A	n/a	28	0	0	0	0.1	0.1
		CNYPL13	Fourth Sawyer 230-23kV Bank (N-1-1)	N/A	N/A	N/A	N/A	n/a	26	0	0	0	0.1	0.1
		CNYPL34	Install Capacitance/TRV	N/A	N/A	N/A	N/A	n/a	33	0	0	0.3	0.7	1
		C30806	Install new Alps Site Sub-Nassau	Open	N/A	N/A	N/A	n/a	27	1.1	0.8	0	0	1.9
		C33619	Install new Alps Site Sub-Line Work	Open	N/A	N/A	N/A	n/a	49	0.1	0.2	0.2	0	0.4
		CNYPL29	Lake Colby - Spare SVC Transformer and Thyristor	N/A	N/A	SG115	February 5, 2010	No	28	0.1	1.7	0	0	1.8
		C32259	Lowville Automated 115 kV Switches	Open	N/A	SG116	October 8, 2009	No	49	0.1	0.2	0	0	0.3
		C24064	LTC Filtration Systems NY	Open	N/A	N/A	N/A	n/a	21	0.1	0	0	0	0.1
		CNYPL33	Reconductor 24 & 25 Line - Hogan Taps to Panell Road	N/A	N/A	N/A	N/A	n/a	35	0	0	0.1	1.5	1.6
		CNYPL1	Reconductor Black River LHH	N/A	N/A	N/A	N/A	n/a	40	0	0	0.1	5	5.1
		C27163	Replace N. Angola 115:34.5kV Banks	Open	N/A	SG083	February 26, 2008	No	36	0	0.4	5.3	0	5.7
		CNYPL26	Replace overdutied 115kV breakers at Central and Mohawk Valley	N/A	N/A	N/A	N/A	n/a	39	0	0.2	1	1.8	3
		CNYPL25	Replace overdutied 115kV breakers at	N/A	N/A	N/A	N/A	n/a	39	0	0.2	1	1.8	3

		CNYPL24	Replace three 115kV breakers at	N/A	N/A	SG115	February 5, 2010	No	39	0	0	0.3	0.6	0.9
		C29964	Reynolds Road - Cap Blocking	Open	N/A	N/A	N/A	n/a	28	0	0	0	0	0
		C30826	Spier West 9 115kv Switch Add	Cancelled - Combined C21694	N/A	SG080 SG029v3	March 28, 2008 April 22, 2009	No	34	0	0	0.1	0.2	0.3
		C10705	Sta Homer Hill Transformers	Open	N/A	N/A	N/A	n/a	20	0	0	0	0.2	0.2
		CNYPL28	Syracuse Area Reconductoring	N/A	N/A	N/A	N/A	n/a	19	0	0	0.3	1.6	1.9
		C08376	Transmission Study Budgetary	Reserve	Reserve	Reserve	Reserve	Reserve	49	0.2	0.2	0.2	0.2	0.8
		C28708	Upgrade Breakers at	Open	N/A	SG096	October 8, 2008	Yes	40	2	1.5	0	0	3.5
		C33252	Upgrade Breakers at	Open	N/A	SG096	October 8, 2008	Yes	49	2	0.5	0	0	2.5
		C29945	Upgrade Niagara-	Open	N/A	SG103	December 4, 2008	No	40	0	0	0	0.2	0.2
	Other System Capacity & Performance Total									**5.8**	**7.3**	**10**	**21**	**44.1**
	Overhead Line Refurbishment Program	C24359	Browns Falls - Taylorville 4 Lightning Enhancements	Open	N/A	SG080	March 28, 2008	No	37	4.6	0	0	0	4.6
		C24360	Coffeen - LH 5 T2120 Lightning	Open	N/A	SG080	March 28, 2008	No	37	0.8	0	0	0	0.8
	Overhead Line Refurbishment Program Total									**5.4**	**0**	**0**	**0**	**5.4**
	Reliability Criteria	C24014	Andover Cap Bank, part of	Open	AMIC0932	SG075v2	April 24, 2009 May 15, 2009	No	39	0.4	0	0	0	0.4
		C31478	Batavia Second 115kV Cap Bank, part	Open	N/A	SG077v3	January 18, 2010	Yes	34	0.1	0.1	1.1	0	1.3

		C24016	Construct Southwest Station (Line Station), part	Open	N/A	SG075v2	May 15, 2009	No	39	0.6	1.5	0.8	0	2.8
		C24015	Construct Southwest Station, part of	Open	N/A	SG075v2	May 15, 2009	No	39	5	18	2	0	25
		C24629	Conversion of #109 to 115kV-	Open	N/A	SG077v3	January 18, 2010	Yes	34	0.2	1.6	9.2	0	10.9
		C31460	Dunkirk Second Bus Tie- Line, part	Open	N/A	SG075v2	May 15, 2009	No	19	0	0.1	0.1	1.1	1.2
		C31459	Dunkirk Second Bus Tie- Station,	Open	N/A	SG075v2	May 15, 2009	No	19	0	0.1	0.3	1	1.4
		C24631	Golah work for #109 Conversion -	Open	N/A	SG077v3	January 18, 2010	Yes	34	0.5	2	3	0	5.5
		C31457	Homer Hill 115kV Capacitor Banks, part of	Open	N/A	SG075v2	May 15, 2009	No	28	1	0.2	0	0	1.2
		C24630	Mortimer Work for #109 Conversion -	Open	N/A	SG077v3	January 18, 2010	Yes	34	0.3	1.6	2.1	0	4
		C24019	Rebuild line #181 and #180 (Station Work), part of SG075	Open	N/A	SG075v2	May 15, 2009	No	27	0.1	0.1	1.5	1	2.7
		C24018	Rebuild line #181 and	Open	N/A	SG075v2	May 15, 2009	No	27	1.5	2	13	20	36.5
		C31463	Reconductor portions of 54 and 181, part	Open	N/A	SG075v2	May 15, 2009	No	19	0	0.2	0	0	0.2
		C24017	Reconductoring of #171, part	Open	N/A	SG075v2	May 15, 2009	No	39	0.8	2.3	0.2	0	3.2
		C31458	Replace HH Ckt #157 Connections,	Open	N/A	SG075v2	May 15, 2009	No	28	0.1	0	0	0	0.1
		C33884	Replacement of #171 connections,	Open	N/A	SG075v2	May 15, 2009	No	49	0	0.1	0	0	0.1

		C31482	Second 115kV bus tie at Lockport, part	Open	N/A	SG077v3	January 18, 2010	Yes	34	0.7	0	0	0	0.7
		C31479	Upgrade Batavia South 115kV busring, part of SG077	Open	N/A	SG077v3	January 18, 2010	Yes	28	0.1	0.2	0	0	0.3
		C31481	Upgrade capabiity of L107, part of	Open	N/A	SG077v3	January 18, 2010	Yes	34	0.2	0	0	0	0.2
	Reliability Criteria Compliance Total									**11.6**	**29.8**	**33.3**	**23.1**	**97.7**
	Reserve	CNYX33	Resreve	Reserve	Reserve	Reserve	Reserve	Reserve	49	-7.8	-12.2	-4.5	-2.9	-27.4
	Reserve Total									**-7.8**	**-12.2**	**-4.5**	**-2.9**	**-27.4**
Transmission Total										**46.3**	**81.1**	**51**	**46.8**	**225.3**
Total System Capacity & Performance										**119**	**139.7**	**121**	**122.5**	**502.3**

Network Segment	Program	Project Number	Project Name	Project Status	Sanction paper	Strategy paper	Confidential Y/N	Risk Score	FY11	FY12	FY13	FY14	FY11-14
Transmission	3A/3B Tower Strategy	C08017	Leeds - Pleasant Valley 91/92 Tower Reinforcement - includes public safety	Open	N/A	SG032,SG080	No, No	49	0	0	0.1	0.1	0.2
		C07918	New Scotland - Leeds 93/94 Tower Reinforcement - Public	Open	N/A	SG032	No	49	0	0.1	0.1	6	6.2
	3A/3B Tower Strategy Total								**0**	**0.1**	**0.2**	**6.1**	**6.3**
	Battery Strategy	C24239	Battery Strategy FY09 Co. 36 Txt	Open	N/A	SG013	No	22	0.3	0.3	0	0	0.7
		C32957	Battery System Replacement Program	Open	N/A	SG013	No	34	0.3	0.3	0	0	0.5
		C33847	BatteryRplStrategyCo3 6TxT	Open	N/A	SG128	No	39	0.6	0.6	0.6	0.6	2.5
	Battery Strategy Total								**1.2**	**1.2**	**0.6**	**0.6**	**3.7**
	Circuit Breaker Replacement Strategy	C31661	Inghams-replace 115kv OCB	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	35	0.1	0.2	1	5	6.3
		CNYAS24	Meco - Replace 115kV PTs and circuit breakers	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	35	0	0	0.3	1	1.3
		CNYAS39	Mortimer 115kV - refurbish / replace circuit breakers	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	35	0	0	0	0.3	0.3
		CNYAS07	NY Circuit Breaker Replacement (Priority 4)	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	35	0.1	0.9	6	8	15
		CNYAS06	NY Circuit Breaker Replacement Priority 3)	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	26	0	0	0	0.2	0.2
	Circuit Breaker Replacement Strategy Total								**0.1**	**1.1**	**7.3**	**14.5**	**22.9**
	Flying Ground Strategy	CNYX30	Strategy to Replace Flying Ground Switches	N/A	N/A	SG124	No	22	0	0	0.3	1	1.3
	Flying Ground Strategy Total								**0**	**0**	**0.3**	**1**	**1.3**
	Other Asset Condition	C28304	Alps #188 Obsolete Circuit Switcher	Open	N/A	N/A	N/A	16	0.2	0.7	0	0	0.9
		C27082	Ash to Teall Cathodic Protection Upgrade	Open	N/A	N/A	N/A	28	0	0.1	0	0	0.1
		C31005	Bristol Hill Repl SWs 46 & 47	Open	N/A	TS0720081367 TS0720081368	No, No	28	0	0.2	0	0	0.2
		C31950	Butler Sta 64 -RPL LN182	Open	N/A	PIW 062-2007	No	43	0.6	0	0	0	0.6
		C29844	Colton Replace CBs and disconnects	Open	N/A	N/A	N/A	34	0.9	0.9	0.9	0	2.8
		C31867	Dewitt-Rebuild 345kv	Open	AMIC0913	N/A	No	49	0.3	0	0	0	0.3
		C27845	Dunkirk 230kV Control Cable TB1	Open	AMIC0951	N/A	No	34	0.8	0	0	0	0.8
		C31025	Edic Station - Replace TB2, 3, 4 Metering	Open	N/A	TS820081404	No	40	0	0.1	0	0	0.1
		C03383	EJ West-Warrensburg 9 115kV Cross Bracing	Open	N/A	N/A	N/A	16	0	0	0	0.1	0.1
		C30528	Elm Terminal Station - HPFF Alarms	Open	N/A	PIW from Len Fiume dated 11/29/2007 Email	No	35	0	0.1	0	0	0.1
		C03384	Elnora 115kV Tap Cross Bracing	Open	N/A	N/A	N/A	16	0	0	0	0.1	0.1
		C03281	Fenner-Cortland 3 Cross Braces	Open	N/A	N/A	N/A	21	0	0	0	0.1	0.1
		C27829	Gardenville Control Cables	Open	N/A	N/A	N/A	34	0.3	0	0	0	0.3
		C30530	Gardenville Station - HPFF Alarms	Open	N/A	PIW from Len Fiume dated 11/29/2007 Email	No	35	0	0.1	0	0	0.1
		C31004	Gibson Sta - Repl SW1602,03, R1617,18	Open	N/A	TS0620081338 TS720081389 TS720081390	No. No, No	28	0.1	0.3	0.3	0	0.6
		C31663	Greenbush- Replace TB3	Open	N/A	N/A	N/A	39	0	0.6	1	0	1.6

		C29950	Harper Station - Replace 2023 & 2033 MODs	Open	N/A	TS0420081278	No	22	0	0.1	0.3	0	0.5
		C30531	Huntley Station - HPFF Alarming	Open	N/A	PIW from Len Fiume dated 11/29/2007 Email	No	35	0	0.1	0	0	0.1
		C28044	Lafayette - Replace Line 4 Relaying	Open	AMIC08127	N/A	Yes	39	0.1	0	0	0	0.1
		C03748	Leeds SVC-Refurbishment/Replacement	Open	AMIC0989 - TIC0923	SG059	Yes (AMIC Paper), NO (SG059)	36	5.9	0	0	0	5.9
		C27042	New Gardenville - TB3 &TB#4	Open	N/A	SG113	No	34	3.7	0	2.8	2.8	9.3
		C31658	NY Surge Arrester Replacement	Open	N/A	No Strategy required, refer to SMP	No	36	0	0	2.7	2.6	5.3
		C29216	Oswego - Replace Special	Open	N/A	TS920081420	Yes	35	0	0.7	0	0	0.7
		C27006	Packard Replace TB3 &TB4	Open	N/A	SG113	No	41	6.4	0	0	0	6.4
		CNYX72	PIW Prospective Projects	N/A	Reserve	Reserve	N/A	49	1	1.5	1.5	3	7
		C20912	Porter Replace 11 GE 230kV RF2 Discs	Open	N/A	N/A	N/A	28	0.5	0.4	0	0	0.9
		C30532	Rochester Generator and HPFF Alarms	Open	N/A	PIW from Len Fiume dated 11/29/2007 Email	No	39	0	0.1	0	0	0.1
		C15988	Rochester HPFF Cable Plant	Open	N/A	N/A	N/A	44	0	0	0.9	0.1	1.1
		C29946	Rochester Pump - LPFF Trip Scheme	Open	N/A	PIW from Len Fiume dated 11/29/2007 Email	No	35	0	0	0.4	0	0.4
		CNYAS38	Silver Creek switch structure - replace 115kV disconnects	N/A	N/A	N/A	N/A	21	0	0	0	0.3	0.3
		C31044	Taylorville Repl SW #23	Open	N/A	TS720081392	No	34	0	0.1	0	0	0.1
		CNYX26	Temple Pressuring Plant	N/A	N/A	N/A	N/A	28	0	0	0	0	0
		C32309	Ticonderoga-Sanford T6410R Removal	Open	N/A	TL0520081301	No	43	0	0.1	0.2	0	0.2
		C11318	Trinity UG Pumphouse Redesign	Open	N/A	N/A	N/A	49	0.7	0.3	0	0	1
		C29951	Youngmann Terminal Station - Replace Switch #310	Open	N/A	TS0420081265	No	19	0.1	0	0	0	0.1
	Other Asset Condition Total								21.8	6.9	11	9.1	48.3
	Overhead Line Refurbishment Program	CNYAS62	Dunkirk - Falconer #161	N/A	N/A	SG080	No	40	0	0	0.1	0.1	0.2
		CNYAS49	Dunkirk - Falconer #162	N/A	N/A	SG080	No	44	0.1	0.1	0.2	1	1.4
		C27422	Falconer-HH 153-154, T1160-T1170 ACR	Open	N/A	SG080	No	39	0	0.1	0.2	1	1.3
		C03389	Gard-Dun 141-142 T1260-1270 ACR	Open	N/A	SG080	No	44	0.5	9	27	15	51.5
		CNYAS60	Gardenville - Buffalo Sw #146 [145]	N/A	N/A	SG080	No	18	0			0.1	0.1
		CNYAS75	Gardenville - Dunkirk #74	N/A	N/A	SG080	No	40	0	0	0.1	0.1	0.2
		C27425	Gardenville -HH 151-152, T1950-T1280-S ACR	Open	N/A	SG080	No	39	0.1	0.1	1	1	2.2
		C27436	Gardenville Lines 180-182, T1660-T1780 ACR	Open	N/A	SG080	No	44	0.1	0.1	0.1	12.5	12.7
		C04718	Gard-HHI 151-152, T1950-T1280 N ACR	Open	AMIC08117 - TIC 0819	SG080	No, No	49	9.9	6.7	0	0	16.6
		C27429	Homer Hill Bennett Rd 157, T1340 ACR	Open	N/A	SG080	No	39	0.1	0.1	0.1	0.1	0.3
		CNYAS53	Huntley - Lockport #37	N/A	N/A	SG080	No	44	0.1	0.1	0.1	0.1	0.3
		CNYAS51	Huntley - Praxair #46	N/A	N/A	SG080	No	18	0	0.1	0.1	0.1	0.3
		CNYAS63	Huntley-Gardenville 38 (& 39) (refurb)	N/A	N/A	SG080	No	40	0	0	0	0.1	0.1
		CNYAS56	Indeck Oswego - Lighthouse Hill #2	N/A	N/A	SG080	No	39	0.1	0.1	0.1	6	6.2
		C27432	Lockport 103- 104, T1620-T106 STR	Open	N/A	SG080	No	40	0.1	0.1	0.1	0.1	0.3
		C03417	Lockport Mortimer 111 T1530 ACR	Open	N/A	SG080	No	49	1.6	12	21	12	46.6
		C03422	Lockport-Batavia 112, T1510 ACR	Open	N/A	SG080	No	39	0	0.2	2.5	12.3	15
		C27431	Lockport-Bativa 108 Refurb	Open	N/A	SG080	No	29	0	0.1	0.1	0.1	0.2

		C18670	Lockport-Mort 113-114, T1540-T1550	Open	AMIC0984 - TIC 0919	SG080	No, No	49	1.8	0	0	0	1.8
		C33014	Lockprt-Mort 111 Tap T1530-1 Refurb	Open	N/A	SG080	No	39	0	0.1	0.3	0	0.4
		CNYAS65	Mortimer - Pannell Road #24	N/A	N/A	SG080	No	40	0	0.1	0.1	0.1	0.2
		C30889	Pannell-Geneva 4-4A, T1860 ACR	Open	N/A	SG080	No	37	0.1	0.1	0.1	14.1	14.3
		CNYAS77	Porter - Rotterdam #30	N/A	N/A	SG080	No	40	0	0	0	0.1	0.1
		C30890	Porter Rotterdam 31, T4210 ACR	Open	N/A	SG080	No	45	0.1	0.1	0.1	9.9	10.2
		C27437	Taylorville -B 5-6 T3320-T3330 ACR	Open	N/A	SG080	No	39	0.1	0.1	0.6	5.4	6.2
		C24361	Taylorville-Moshier 7, T3340 ACR	Open	N/A	SG080	No	49	2.4	3.5	0	0	5.9
		CNYAS82	Ticonderoga Lines 2 (& 3) (Complete Line)	N/A	N/A	SG080	No	40	0	0	0.1	1	1.1
		C19530	Ticonderoga-2-3, T5810-T5830 SXR	Open	AMIC08107 - TIC0818	SG083v1d	No, No	49	3.2	0	0	0	3.2
	Overhead Line Refurbishment Program Total								**20.2**	**32.6**	**53.7**	**92**	**199.4**
	Relay Replacement Strategy	CNYAS29	Browns Falls - protection repalcement and new control	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0	0	0
		CNYAS31	Edic - Protection replacement	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0.1	0.5	0.6
		CNYAS90	Geres lock Control room & Relay Strategy	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0	0	0
		CNYAS41	Menands - new control building	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	28	0	0.3	0.3	1	1.5
		CNYAS26	North Troy - protection replacement	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0	0.1	0.1
		CNYAS10	NY Protection & Control Replacement	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	35	0.1	0.8	3.3	4.3	8.4
		CNYAS32	Oswego - new control building	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0.1	0.5	0.6
		CNYAS88	Relay Replacement Strategy - Phase 2	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0	0	0
		CNYAS89	Riverside Control room & Relay Strategy	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0	0	0
		CNYAS28	Yahnundasis - protection replacement	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	19	0	0	0	0.1	0.1
	Relay Replacement Strategy Total								**0.1**	**1**	**3.8**	**6.5**	**11.3**
	RHE Breaker Replacement	C24299	Lighthouse Hill Road - Repl R60 RHE PCB	Cancelled	N/A	Please refer to January 2010 CIP Filing for	N/A	39	0.1	0.2	0	0	0.3
		C18410	Oneida - R/R 115kV FP RHE OCB's	Open	N/A	Please refer to January 2010 CIP Filing for	N/A	39	0	0.1	0.5	0	0.6
	RHE Breaker Replacement Total								**0.1**	**0.3**	**0.5**	**0**	**0.9**
	Shield Wire Strategy	C28683	Shieldwire: Buffalo 145	Open	N/A	SG073	No	40	0.3	1.3	0	0	1.6
		C28709	Shieldwire: Clay-Dewitt 3	Open	AMIC0910 - TIC0905	SG073	Yes (AMIC Paper), No (SG073)	40	1.2	1.2	0	0	2.4
		C28706	Shieldwire: Gardenville -Depew 54	Open	N/A	SG073	No	40	0	1.1	0	0	1.1

		C28679	Shieldwire: Gardenville Homer 151/152	Open	N/A	SG073	No	40	0	3.6	0	0	3.6
		C28676	Shieldwire: Huntley - Gardenville 38	Open	AMIC0894	SG073	No, No	40	1.5	0	0	0	1.5
		C28707	Shieldwire: Huntley-Lockport 36/37	Open	AMIC0895	SG073	No, No	40	1.5	0	0	0	1.5
		C28678	Shieldwire: LaFarge Pleasant Vl 8	Open	AMIC0873 - TIC0812	SG073	No, No	40	1.7	0	0	0	1.7
		C28681	Shieldwire: Mountain-Lockport 103	Open	AMIC08100	SG073	No, No	40	1.3	0	0	0	1.3
		C28712	Shieldwire: Walck Rd - Huntley	Open	AMIC0896	SG073	No, No	40	0.6	0	0	0	0.6
	Shield Wire Strategy Total								**8.2**	**7.2**	**0**	**0**	**15.3**
	Steel Tower Strategy	C21693	S. Oswego Lighthouse Hill Circuits	Open	N/A	SG18v2 SG29v2c SG048	No, No, No	49	4.5	0.4	0	0	4.9
	Steel Tower Strategy Total								**4.5**	**0.4**	**0**	**0**	**4.9**
	Substation Rebuilds	CNYAS40	Buffalo 115kV - replace disconnects	N/A	N/A	N/A	N/A	21	0	0	0	0.3	0.3
		C05155	Dunkirk Rebuild	Open	N/A	Please refer to January 2010 CIP Filing for justification	N/A	35	0	0	0.1	0.5	0.6
		CNYAS91	Elm St. Refurbishment	N/A	N/A	N/A	N/A	35	0	0	0.5	1	1.5
		C05156	Gardenville Rebuild	Open	N/A	SG112	Yes	35	0.5	2.7	36.4	23	62.6
		C30084	Gardenville Rebuild Line Location	Open	N/A	SG112	Yes	44	1	1.2	1.3	0.1	3.6
		C31662	LightHH 115kv Yard Repl & cntrl hse	Open	N/A	N/A	N/A	35	0.3	1	5	5	11.3
		CNYAS2	Lockport Rebuild	N/A	N/A	N/A	N/A	35	0	0	0.3	1	1.3
		CNYAS44	Mohican - rebuild including transformers and oil circuit breakers	N/A	N/A	N/A	N/A	35	0.1	0.2	1	10	11.3
		C29180	N. Leroy Rebuild Station	Open	N/A	N/A	N/A	34	0.1	0	0	0	0.1
		CNYAS36	Porter 230kV - replace disconnects and PTs	N/A	N/A	N/A	N/A	28	0	0.3	1	10	11.3
		CNYAS27	Reynolds Road - protection repalcement & new control building $ replace. Overduty 115kv Breakers	N/A	N/A	N/A	N/A	19	0	0	0.5	1	1.5
		C03778	Rome 115 kV Station	Open	N/A	SG123	No	22	0.4	2	8.7	2.1	13.2
		C17849	Rotterdam R/R 230kV EPE RHE CB's	Open	N/A	N/A	N/A	39	0.5	1.6	4	15	21.1
	Substation Rebuilds Total								**2.8**	**8.8**	**58.9**	**68.9**	**139.4**
	Transformer Replacement Strategy	C31656	NY 115kv Transformer Replace (Priority 4)	Open	N/A	Please refer to January 2010 CIP Filing for justification	N/A	41	4	7	7	7	25
	Transformer Replacement Strategy Total								**4**	**7**	**7**	**7**	**25**
	U-Series Relay Strategy	C24662	Edic FE1 - Replace U Series Relays	Open	N/A	SG012	Yes	33	0.3	0	0	0	0.3
		C24663	Leeds - Replace U Series Relays	Open	N/A	SG012	Yes	33	0.2	0.7	0	0	0.9
		C24661	LN17- Replace Type U Relays	Open	N/A	SG012	Yes	33	1.4	0	0	0	1.4
		C05150	Westinghouse U Series Relay Strategy	Open	N/A	SG012	Yes	33	0.5	0	0	0	0.5
	U-Series Relay Strategy Total								**2.3**	**0.7**	**0**	**0**	**3**
	Reserve	CNYX31	Resreve	Reserve	Reserve	Reserve	N/A	49	-9	-9.2	-14.1	-18.6	-50.9
	Reserve Total								**-9**	**-9.2**	**-14.1**	**-18.6**	**-50.9**
Transmission Total									**56.2**	**57.6**	**129**	**187**	**429.7**
Total Asset Condition									**114.3**	**122.9**	**193.1**	**280.5**	**690.8**

Response IR MJR-1 Transmission--Non-Infrastucture

Network Segment	Program	Project Number	Project Name	Project Status	Sanction paper	Strategy paper	Approved Sanction/Strategy Date	Confidential (Y/N)	Risk Score	FY11	FY12	FY13	FY14	FY11-14
Transmission	Other - Non Infrastructure	CNYAS87	Asset Separation strategy	N/A	N/A	N/A	N/A	n/a	39	0	0	0	0.1	0.1
		CNYAS46	Flood mitigation	N/A	N/A	Please refer to Request No. AJR-1 - NMPC Request No. NM 45 DPS 42	N/A	No	22	0	0	2	1	3
	Other - Non Infrastructure Total									**0**	**0**	**2**	**1.1**	**3.1**
	Physical Security	CNYAS86	Physical Security Strategy	N/A	N/A	SG132	2/25/2010	Yes	40	0.1	6	3	0	9.1
	Physical Security Total									**0.1**	**6**	**3**	**0**	**9.1**
Transmission Total										**0.1**	**6**	**5**	**1.1**	**12.2**
Total Non-Infrastructure										**3.3**	**11.4**	**10.6**	**6.9**	**32.2**

Date of Request: March 4, 2010
Due Date: March 15, 2010

Request No. RAV-42
NMPC Req. No. NM 174 DPS 104

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirement Panel

Request:

A. Please provide a comprehensive list of all non-Mercer initiatives, along with the estimated annual savings, that the Company is currently pursuing. Provide the amounts, broken down into "those included on tab WP1 of the Company's Keyspan merger savings estimate spreadsheet," "those not included on tab WP1 of the Company's Keyspan merger savings estimate spreadsheet," and "total."

B. Please provide a breakdown of the $200 million in KeySpan merger savings aligned with the $246.9 million of "Day N" KeySpan merger savings shown in Column V, Rows 7 - 434 of tab WP1 of the Company's KeySpan merger savings estimate spreadsheet.

C. 1. In general terms, fully explain what is the difference between the "Day N" KeySpan merger initiative savings and the KeySpan merger "run rate" initiative savings. Why are "Day N" savings more than "run rate" savings?"
2. Fully explain how "Day N" KeySpan merger initiative savings can be less than
the
KeySpan merger "run rate" initiative savings for each of the following items:
Row Run Rate Day N
a. 9 $2.2M $0.7M
b. 38 $2.17M $0.21M
c. 102 $0.97M $0.11M
d. 109 $3.56M $2.57M
e. 164 $1.37M $0.73M
f. 245 $12.18M $9.91M
g. 275 $3.62M $2.06M
h. 292 $4.86M $1.07M
i. 335 $1.72M $0.75M
j. 389 $2.63M $1.37M

Form 103

3. Should the "Day N" savings be increased from $246.9M to reflect the higher "run rate" savings for each of the above items a.-j? If so, by how much? If not, fully explain why not.

D. Why are there cumulative "run rate" savings of $10.093M for initiatives in rows 220-230, but $0 "Day N" savings for the same initiatives? Should the "Day N" savings be increased from $246.9M to reflect these initiatives in rows 220-230? If so, by how much? If not, fully explain why not.

E. Please identify and explain the $473K of achieved savings in row 238 (no initiative title is provided on the spreadsheet for this item).

F. Please fully explain how there can be negative synergy savings associated with each of the initiatives on rows 11-13, 15-17, 22, 280, 281, 322 and 371-372. Are these actually costs to achieve?

G. Fully explain and provide a breakdown of what the negative $33.2M of "Day N" synergy savings associated with "Initiatives From Business Transformation" represent (row 316) and why they are included as Day N synergy savings? Are these actually costs to achieve?

H. The Company's methodology for determining actually achieved historic test year (YE 9/09) KeySpan synergy savings is to take actual FYTD 9/09 + actual FYE 3/09 – FYTD 9/08, as shown on Exhibit RRP-2, Schedule 42, Sheet 3. However, on the below initiative rows, it is Staff's belief that this methodology overstates the actual achieved savings in the historic test year. To illustrate this overstatement of achieved actual savings, row 244 shows actual FYTD 9/08 savings of $0.4111M, FYE 3/09 savings of $2.283M (which is also the run rate, meaning the savings have been fully achieved within FYE 3/09) and FYTD 9/09 (which is a 6 month period) achieved savings of $1.1415M, or exactly 50% of the annual savings. However, the Company's methodology for determining actual achieved historic test year (YE 9/09) savings results in $3.0134M of such savings rather than $2.283M of true savings (i.e., $1.1415M + $2.283M - $0.4111M).

1. Please indicate if the Company agrees its methodology overstates actually achieved historic test year (YE 9/09) KeySpan synergy savings on the synergy saving initiative in row 244 for the above stated reason. If not, fully explain how it is possible to obtain more than $2.283M of annual savings from this initiative.
2. Please provide a recalculation of actual achieved historic test year (YE 9/09) KeySpan synergy savings on the following rows, which all have the same inherent problem of overstated historic test year savings: 48, 71, 102, 109, 164, 170, 175, 244, 248, 292, 358, and 359.
3. Please indicate if you agree that the actual achieved historic test year (YE 9/09) KeySpan synergy savings should be reduced to correct for this observed overstatement. If not, explain in full why not.

Response:

A. Please see Attachment 1 to this response for a listing of all non-Mercer initiatives. Workpaper 1 is used by the Company to record synergy savings each quarter. Therefore, all replacement initiatives which were not originally listed in the Mercer presentation have been included here. There is also the potential to include savings arising from the implementation of the Transaction Delivery Centre (TDC). The TDC would not have been possible without the acquisition of Keyspan and as a result, a proposal is to be put to the Heads of Finance Committee for their approval to include these savings against the $200 million synergy target. Although this has been included on the listing on Attachment 1, it is not currently contributing to the synergy savings and will only do so, providing approval is received from the Heads of Finance.

B. The Company does not maintain a breakdown of the $200 million target by initiative. Please see the responses to Information Request RAV-41, Parts B.2. and E.1. for an explanation of the difference between the $246.9 million Day N savings and the $200 million in Keyspan merger savings. It is not possible to reconcile each initiative from the nominal $246.9 million to the agreed target of $200 million other than to apply a simple ratio against each initiative. Certain initiatives included in the nominal $246.9 million will exceed their targets and others will not be completed at all. The $200 million target was determined by taking the high confidence range target of $215 million and the low confidence target of $160 million and determining a value which would provide management with a stretch goal as detailed in the response to Information Request RAV-41, Parts B.2. and E.1.

C.1. The response to Information Request RAV-41 Parts B.2., E.1. and E.3. explain the detail process behind the total Mercer savings target. In essence, these were a list of initiatives at the 100% confidence level for the company to achieve the stipulated $200 million annual savings. Thus the nominal Mercer savings amount of $246.9 million represents the Day N target. The run rate is the savings being reported against each individual initiative which will accrue during the following year. The run rate savings therefore represent the current progress against the Day N Mercer targets.

C.2.a. The run rate savings for September 2009 were not calculated correctly from the fiscal savings. The new rate savings were adjusted downwards in the December 2009 synergy report to just under $1 million of savings.

C.2.b. The $2.17 million represents labor savings across finance. The savings have been tracked in a single initiative rather than split out among the others listed in the table.

C.2.c. A number of initiatives have been grouped together and this initiative is being used to report the total savings.

C.2.d. An additional floor in the Company's offices in MetroTech Brooklyn was vacated enabling the company to achieve greater than planned savings.

C.2.e. The assumptions made at the time of the Mercer targets regarding OpEx/CapEx split on the FTEs were updated, resulting in a higher actual OpEx allocation.

C.2.f. All savings in relation to IS staff reductions for KeySpan integration are captured under the IS Functional Consolidation initiative unless they are directly associated with other identified IS initiatives. The savings target for this initiative was an estimate based on a mix of roles and numbers of people with those roles. The savings target has been exceeded as a result of the salaries of a number of people, who have left from various roles, being higher than originally estimated in the target.

C.2.g. The September 2009 run rate was overstated. Following a review, it was noted that the savings being reported were due to "call avoidance" related savings that were not truly synergy savings. This was adjusted for the December 2009 synergy report.

C.2.h. The original synergy savings targets were based on a reduction of 11 FTE's. However, over time there have been a significant number of organizational changes which have eliminated a number of positions. To date, the savings are based on a reduction of approximately 38 FTE's which accounts for the excess over the Mercer target.

C.2.i. The synergy savings are reported against FIN_TR_12 although the savings are from across treasury which would also include initiatives FIN_TR_5, 8, 9, 10, 13, and 14.

C.2.j. The additional savings are due to approximately 10 FTE's who have either left or retired and the positions are not going to be staffed.

C.3. The $246.9 million is a nominal target and as such has limited relevance as to the level of savings likely to be achieved on Day N. The response to Information Request RAV-41, parts B.2. and E.1. explains the overall target. The $200 million represents a stretch goal for the Company and will be difficult to achieve. It is anticipated that some initiatives will exceed their targets while a number of others will fall short. Therefore, the Company believes at this stage that no adjustment to the Day N total is necessary.

D. The initiatives listed in rows 220-230 have zero Day N savings because they were not part of the original Mercer project list. As Gas Distribution developed more detailed plans and analysis of the original Mercer projects, some were deemed not feasible due to regulatory, union, cost-benefit analysis or other reasons. As a result, Gas Distribution developed alternate projects to capitalize on the integration and achieve target benefits. These projects were not specifically intended to cover the gap created by the removal of Automatic Meter Reading ("AMR") from the list of possible synergy savings, although they will contribute to filling-in the gap. Gas Distribution has no plans to replace the AMR-related savings (i.e., Day N target for Gas Distribution is $27.8M, not $47.8M). The Company therefore believes at this stage no adjustment to the overall Day N total is necessary.

E. The title of the item on row 238 should be Six Sigma. This initiative is related to reducing leak expenses in New York City by applying a Six Sigma approach.

F. The costs associated with the initiatives listed in Part F. above are not costs to achieve. Costs to achieve are one time expenses and these are ongoing business costs and the expectation is that they will occur year after year. At the time these initiatives were identified, there was a need to fill a resourcing issue within a particular function or process. In other words, that activity was not currently taking place and was required, or by introducing this resource it would enable other initiatives to achieve their savings.

G. The synergy target for Electric Distribution, which was developed during the integration process described in RAV 41 E.1., is $20.05 million. However, the Company embarked on a more ambitious transformation program within Electricity Distribution Operations which leveraged off of the initiatives identified during the integration process but had a wider scope. The Company is treating the first $20.05 million of the savings associated with Electric Distribution transformation as integration savings. The $33.65 million is an adjustment to reflect the difference between the EDO transformation savings and the designated synergy savings. It is not a cost to achieve.

H.1. The Company did not calculate the test year savings on an individual initiative basis. Aggregate totals of all initiatives from each line of business were used to calculate the test year savings.

Continued refinement of the synergy tracking process by individual initiatives is ongoing and as a result savings reported for past periods may have been reasonable in the aggregate but not individually. This could be attributable to situations such as transfers between initiatives and organization changes. The aggregate totals smooth out any inconsistencies in information. For example, row 219 for September 2008 included the total of savings for Gas Distribution at that date. In subsequent periods these savings were allocated to other initiatives.

The Company believes that calculating initiatives on an aggregate basis from each line of business would provide a similar result as calculating the test year savings on an initiative by initiative basis. For example, in the specific rows identified in Part H. above, it is agreed that there would be an overstatement of savings against those particular initiatives. However, for row 219 there would be an understatement.

H.2. Please see Attachment 2 to this response which details a reduction to the test year savings of $684k if we apply the methodology which limits the savings for these initiatives to the run rate. However, please note that this includes an adjustment of $1.6 million of finance savings which were not included in the original submission due to a spreadsheet error.

Synergy tracking has developed since integration. Functional coordinators have been encouraged to adopt a conservative approach when reporting savings and to ensure that the savings have been achieved when they report them. During the first year there was a learning curve for all involved with integration tracking to report synergies accurately on a run rate basis. Discipline in reporting has been improved with the introduction of templates that encourage the reporting of savings on an initiative by initiative basis leading to greater clarity.

Furthermore, the method used to calculate savings is only one method of calculating the savings for the test year. An alternative approach is to take ¼ of the run rate at the start of each quarter and add this to the difference between the run rate at the start of the quarter and the quarter end and divide by 2 to average the increase over the quarter. This would imply an adjustment to the test year level of synergy savings of $920k. This calculation can also been seen on Attachment 2 of this response.

In terms of validity both methods have their merits and the Company chose to go with the lower amount using the aggregate savings for each LoB under the methodology described in Part H.1. above.

H.3. The Company agrees that the historic test year savings should be adjusted for the overstatements as recalculated on Attachment 2 as well as the overstatements identified in responses to Parts C.2.a. and C.2.g. The Company will include the above adjustments as well as additional adjustments identified through a scrubbing process of the historic test year savings on Exhibit__(RRP-2), Schedule 42 in the Corrections and Updates Filing.

<u>Name of Respondent:</u> <u>Date of Reply:</u>

James M. Molloy and Stephen Heywood March 21, 2010

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

List of Intiatives

Initiative Code	Initiative	DAY N $(000)'s	Included on tab WP1
GAS-FIN-01	NE Weather Hedge/Insurance	$1,900.0	Yes
USUK-11	Last Mile Logistics	$2,258.4	Yes
CUST-MS-1D	Install Automatic Meter Reading (AMR) in RI	$1,271.0	Yes
CUST-MS-04	Improve Field Appointment Planning & Reduce Missed Appointments	$510.0	Yes
CUST-MS-10	RI Soft Off	$1,290.0	Yes
USUK-09	Global Gas Leakage Management	$1,650.0	Yes
USUK-01	Keyhole/Coring Technology Strategy	$1,600.0	Yes
CUST-MS-09	Advanced Consumption	$1,850.0	Yes
GAS-SYS-01A	Control Center Consolidation (New England)	$500.0	Yes
USUK-02	Eco Ring Seal Injection Process - cancel		Yes
GAS-FLD-06	Improve Damage Prevention & Data Collection	$400.0	Yes
GAS-SYS-14	Reduce LNG Overhead	$360.0	Yes
CUST-MS-05	Optimize Meter Shops	$270.0	Yes
CUST-SAF-01	Improvement of Employee Safety	$200.0	Yes
GAS-FLD-38	Consolidate LI & NY Sales Fulfillment	$192.0	Yes
GAS-ASM-21	Governance on Design Changes	$75.0	Yes
GAS-FLD-27	Reduce Restoration Costs	$422.2	Yes
GAS-FLD-40	Horizontal Directional Drilling	$0.0	Yes
GAS-FLD-41	Six Sigma	$950.0	Yes
Additional Synergies	Keyspan LTIP	$10,202.5	Yes
Additional Synergies	Alignment of Benfits	$4,191.2	Yes
Additional Synergies	Alignment of Pension Assumption	$6,500.0	Yes
Total Additions		**$36,592.3**	Yes
Negative Synergy	Reservoir Woods	($11,500.0)	Yes
Total Replacement Savings	Currently being included against $200m target	**$25,092.3**	Yes
Potential Synergies	Transaction Delivery Centre	$16,315.0	No
Grand Total	Total potentially contributing to $200m target pending HoF's approval	**$41,407.3**	Total

Niagara Mohawk Power Corporation
d/b/a National Grid
Case 10-E-0050
Attachment 2 to RAV-42
Sheet 1 of 1

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

		Fiscal Savings to Date (in thousands)			Aggregate Run Rate (in thousands)			DAY N	Adjusted	Original
Initiative Code	Initiative	Sep 08	Mar 09	Sep 09	Sep 08	Mar 09	Sep 09	$	Caculation	Calculation
FIN_PN_3	Consolidation of Management Reporting and Planning	$56.3	$225.0	$112.5	$225.0	$225.0	$225.0	$2,381.9	225.0	281.2
HR_BN_01A	Consolidate benefits groups (A)	$149.6	$557.4	$299.2	$598.4	$598.4	$598.4	$642.0	598.4	707.0
P_SVCS_FAC_18A	Procurement-led category sourcing - General Maintenance		$730.5	$487.0		$974.0	$974.0	$110.0	974.0	1,217.5
SVCS_FAC_02	Facility Consolidation - NYC	$499.0	$2,628.3	$1,779.5	$2,404.0	$3,559.0	$3,559.0	$2,572.0	3,559.0	3,908.8
ELEC_DO_10	Gas and Electric System Operations Dispatch (SOD)/Standardize SOD functions/SOD Conso		$1,196.8	$684.2		$1,372.2	$1,372.2	$734.2	1,372.2	1,881.0
GAS_ASM_06C	Encroachment criteria for public works projects - High Priority		$795.3	$375.0		$750.0	$750.0	$964.0	750.0	1,170.3
GAS_FLD_00	Adopt Process Ownership model		$1,851.4	$1,386.6		$2,870.8	$2,780.8	$4,994.0	2,780.8	3,238.0
IS_CVD_1	Contract Volume Discounts	$411.1	$2,283.0	$1,141.5	$925.6	$2,283.0	$2,283.0	$3,496.0	2,283.0	3,013.4
IS_IN_13	Service Management	$60.8	$259.0	$129.5	$0.0	$259.0	$259.0	$354.0	259.0	327.7
CUST_MSG_2	Improved efficiency within existing KeySpan growth model	$1,264.5	$4,777.0	$2,428.0	$4,438.0	$4,857.0	$4,857.0	$1,073.9	4,857.0	5,940.5
CORP_CS_2	Elimination of KS Board of Directors	$552.0	$1,585.0	$792.5	$1,104.0	$1,585.0	$1,585.0	$1,585.0	1,585.0	1,825.5
CORP_CS_3	Elimination of KS Annual Meeting/Printing and Mailing of Annual Report	$72.0	$257.0	$128.5	$144.0	$257.0	$257.0	$257.0	257.0	313.5
									19,500.4	23,824.3

Difference between original and adjusted Calculation				(4,323.92)
Add Back Finance total which was not included in original calculation				1,580.51
Adjustment to Total				(2,743.41)
% Allocated to NiMo				24.93%
Total Adjustment				(684)
Alternate Methodolgy based on Run Rate Caculations	$64,703.6	$128,773.9	$140,454.9	117,347.8
Original Total filed in rate case				113,657.7
Alternate Adjustment				3,690.08
% Allocated to NiMo				24.93%
Total Adjustment				920

Date of Request: March 4, 2010
Due Date: March 15, 2010

Request No. WEL-3
NMPC Req. No. NM 176 DPS 106

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: William Lysogorski

TO: Infrastructure and Operations Panel

Request:

1. Exhibit (IOP-14) Schedule 2 Sheet 68, Table III-6 shows a total budget of $12,500,000.00. The Company's RAV 3 CY-2009 and CY-2008 report shows total expenditures of $481,118.00 and $308,676.00 for TxD_REP-Distribution Automation Pilots. Please provide the work papers supporting how the Company forecasted the FY10/11 – FY14/15 CIP Budgeted dollars.

2. For FY10/11/-FY14/15, please provide the following: If the number of circuits (item a) data is not available, provide the estimated cost per unit of materials used and associated labor cost to install when a circuit is automated.
a. Number of Circuits to receive automation, location and name of circuit, and why they were chosen;
b. Number of reclosers per circuit;
c. Number of switches per circuit;
d. Number of repeater radios per circuit;
e. REFI cost, if any;
f. Total material cost;
g. Total labor cost;
h. Anticipated yearly maintenance cost for equipment used to automate a circuit.

3. The Company's response to IR Request No._PSC-85 Lysogorski (WEL-1), NMPC REQ. No. 86, Case 06-M-0878, and dated 04/10/2008 listed seven pilot programs (Response to 1d). Please provide the status of each of the programs listed. Include the total expenditure for each pilot, description of materials/devices used, and cost associated with the materials/devices, labor costs, and in service date. If a pilot program is not yet in service provide the expected in service date.

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4. For the pilots that are in service, provide the reliability and operational data that has been gathered from these pilots.

5. Provide the risk score for this project (CLINESEC) and the data used to determine the score.

Response:

1.

There are no work papers for this project. At the time the capital investment plan was set, the Company had not identified specific locations or requirements but felt it was necessary to make a budget provision to enable future similar work to proceed.

Following the automation trials listed in the response to Question 3 below, the Company recognized the benefit of identifying additional projects where the installation of either Automation, Preferred / Alternate, or Sectionalizing switching schemes would provide increased reliability to the Sub-transmission network.

Our initial view, without carrying out a detailed engineering review, was that there would be at least 40 – 50 locations where this kind of work would be beneficial but no detailed lists were available. The average costs were estimated to be approximately $250k to $300k per location but again these were conceptual estimates and not supported by detailed cost breakdowns (the average cost of location of the six pilots identified in question 3 is approximately $282k). The budget figure of $12.5M was developed after internal consultation with key stakeholders, recognizing this was an estimate of the likely future costs.

The $500k budgeted in FY10/11 will be used predominantly for engineering activities to identify candidate locations in which to implement automation schemes, the manner/methods of automations schemes, location-specific cost estimates and issue designs. The list of potential candidates for automation is currently under review and is subject to change as new information and performance data become available.

The estimated cost to implement automation may vary considerably by Sub-transmission circuit. This is due to factors such as the number of taps serving significant substation load and the distance between them, the number of automated switches or reclosers needed to segment the line, and where the nearest uplink point for communication to Control Centers is relative to the devices.

2a. For FY10/11 the company has selected five potential candidates to begin detailed engineering for automation. The list below shows the substations and lines being targeted for sub-transmission automation based on the numbers of customers served by the distribution stations supplied by the sub-transmission lines and the potential time necessary to manually switch to an alternate source in the event of an interruption. The approach for automation of these stations is to supply each with a preferred supply and an alternate supply. Therefore, for loss of the preferred supply the scheme will automatically transfer the substation customers to the alternate supply. This will expose customers only to a momentary interruption of approximately 1-minute or less, thus saving these customers from experiencing a sustained interruption

Substation	Division	Line Number	Number of DA Devices	No of Customers
Birch Ave	NYE	8&9	2	1,784
Bolton	NYE	8&9	2	3,360
Fort Gage	NYE	8&9	2	2,280
French Mountain	NYE	8&9	2	534
Wilton	NYE	3&12	2	2,876

FY11/12 through FY14/15 locations for sub-transmission automation schemes will be selected in FY11 in time for FY12 project planning and budget preparation.

2b. The number of reclosers per circuit / installation will vary depending on the number of substations the circuit supplies, the desired segmentation of the line, and the configuration of the supply system. However, in general a preferred/alternate scheme utilizes 2-reclosers. Other schemes may utilize one or more reclosers per line. Many of the automation schemes are unique in nature and need to be developed utilizing a cost and expected benefit type analysis. Those with the greatest benefit/cost will be implemented first.

2c. The number of DA switches per circuit / installation will vary depending on the number of substations the circuit supplies, the desired segmentation of the line, and the configuration of the supply system. However, in general a preferred/alternate scheme utilizes two DA switches. Other schemes may utilize one or more switches per line. Many of the automation schemes are unique in nature and need to be developed utilizing a cost and expected benefit type analysis. Those with the greatest benefit/cost will be implemented first.

2d. The number of repeater radios per circuit is dependent on the location of the nearest uplink point for communication to the Control Centers. Therefore, each installation is unique and communication to Control Centers will vary depending on the communication system best suited for that particular area of the system. There may also be locations where cell phone technology will provide a cost effective alternative.

2e. Radio Equipped Fault Indicators (REFI) were not installed as originally planned due to the cost of communications. See response to Question 3; 'Boonville – Raquette Lake'.

2f. The material cost per circuit will vary depending on the scheme required for each installation and the number of DA devices to be installed for each circuit. However, the conceptual material cost for each DA controlled installation is $60,000.

2g. The labor cost per circuit will vary depending on the scheme required for each installation and the number of DA devices to be installed for each circuit. However, the conceptual labor cost for each DA controlled installation is $40,000.

2h. The yearly maintenance cost for equipment used to automate the circuit will vary depending on the particular type of system installed, the type of devices used, and the desired level of automation. At a minimum, each recloser will have an inspection performed every two months and maintenance every six years for an estimated cost of $5,000 every six years in today's dollars not accounting for inflation.

3. The expenditure for each of the seven Sub Transmission circuits is given below:

Lowville-Boonville #22 23kV Sub Transmission Line –Project is complete

Total Expenditure $338, 029

Materials used included 3 switches, 3 switch controls, and 4 repeater radios with antennas and mounting brackets.

Material Costs	$149,867
Labor Costs	$58,786
Labor Overheads	$42,856
In Service	August, 2008

Lighthouse Hill – Mallory #22 34.5kV Sub Transmission Line- Project is complete

Total Expenditure $647,151

Materials used included 6 switches, 6 switch controls, and 13 repeater radios with antennas and mounting brackets.

Material Costs	$291,376
Labor Costs	$139,923
Labor Overheads	$100,150

In Service December, 2008

Cambridge-Hoosick # 3 34.5kV Sub Transmission Line-Project is complete

Total Expenditure $263,295

Materials used included 1 switch, 1 switch control, and 10 repeater radios with antennas and mounting brackets.

Material Costs $93,146

Labor Costs $67,280

Labor Overheads $50,800

In Service August, 2009

Battenkill-Cement Mountain # 5 34.5kV Sub Transmission Line-Project is complete

Total Expenditure $138,095

Materials used included 1 switch, 1 switch control, and 2 repeater radios with antennas and mounting brackets.

Material Costs $58,366

Labor Costs $28,920

Labor Overheads $21,558

In Service July, 2009

Cement Mountain-Cambridge # 2 34.5kV Sub Transmission Line-Project is complete

Total Expenditure $135,056

Materials used included 1 switch, 1 switch control, and 2 repeater radios with mounting brackets.

Material Costs $53,328

Labor Costs $29,973

Labor Overheads $22,223

In Service August, 2009

Chestertown-Schroon # 3 34.5kV Sub Transmission Line-Project is complete

Total Expenditure $171,924

Materials used included 1 recloser with universal interface module, and 6 repeater radios with antennas and mounting brackets.

Material Costs $67,982

Labor Costs $39,456

Labor Overheads $30,096

In Service August, 2009

Booneville – Raquette Lake 46kV Sub Transmission Line

Preliminary DA pilot analysis included a review for adding Radio Equipped Fault Indicators (REFI) to the Booneville - Raquette Lake 46 kV circuits. At that time the communications system in the Adirondacks was very lacking, even for cell phone coverage. As a result, a large number of repeater radios would have been required and the cost for this option was deemed too large and thus cancelled as not viable in the pilot period. This technology may be considered in the future as part of an option where radio communications already exist, however, it is not expected to be included in any planned projects during the rate period.

4. Reliability and performance data of the six Sub Transmission circuits where DA was completed is given below (Note - this information does not include momentary events as these schemes are only designed to operate for sustained outages):

Lowville-Boonville #22 23kV line
There have been no interruptions on the line since the DA scheme was put in service.

Lighthouse Hill-Mallory #22 34.5kV line
There was one interruption on the line. This interruption was on April 3, 2009 and was on the Lighthouse Hill side of the line. Without the DA scheme, the customers at Sandy Creek substation would have been interrupted. The DA saved 3,781 customers from being interrupted.

Cambridge-Hoosick #3 line
There were no interruptions since the DA was placed in-service.

Battenkill-Cement Mountain # 5 line
There have been no interruptions since the DA was placed in-service.

Cement Mountain-Cambridge #2 line
There have been no interruptions since the DA was placed in-service.

Chestertown-Schroon #3 line
There have been no interruptions since the DA was placed in-service

5. The risk score for project (CLINESEC) is 39. The project score was developed utilizing two components, an impact score of 5 and a likelihood score of 5. The impact score of 5 assumes an outage event would impact on average 3 to 6 feeders. The likelihood score of 5 assumes the likelihood of an outage event would be once every 3 to 5 years.

	1	2	3	4	5	6	7
Likelihood---->	>Once in 100 yrs	Once in 20-100 yrs	Once in 10-20 yrs	Once in 5-10 yrs	Once in 3-5 yrs	Once in 1-3 yrs	>Once in 1 yr
Likelihood---->	1	2	3	4	5	6	7
Likelihood---->	1	2	3	4	5	6	7
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	[illegible]	[illegible]	[illegible]	16	18	23	24
3	[illegible]	[illegible]	[illegible]	21	27	30	31
4	[illegible]	17	19	28	34	36	37
5	15	22	26	35	39	41	[illegible]
6	20	29	33	[illegible]	[illegible]	[illegible]	[illegible]
7	25	32	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Impact							

Name of Respondent:
John Gavin / Rob Sheridan

Date of Reply:
March 22, 2010

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. AAE-10
NMPC Req. No. NM 177 DPS 107

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Allison Esposito

TO: Rudolph L. Wynter Jr.

Request:

1. Please update Exhibit RLW-5 for electric data from 10/1/09 – 2/28/10. In addition to the 12-month average rolling data provided in this exhibit, provide the actual write-offs on a monthly stand alone basis. Please provide monthly updates of this exhibit through the end of the rate case.

2. Does the "Normalized Bad Debt Write-Off Amounts" included in the RLW exhibits represent actual net write offs only for the periods noted or does it also include a component of anticipated additional net write-offs and/or increases in the reserve for bad debts? If it includes a component for anticipated additional net write-offs and/or increases in the reserve for bad debts, provide each amount separately and explain how the amounts were derived.

3. Please state how the LICAP amounts were allocated between electric and gas in Case 08-G-0609. To the extent that these amounts differ from the 72/28% allocation in the current case, please explain this variance and why the Company feels that such a change in methodology is appropriate.

4. Please explain the basis of the current LICAP allocation of 72/28%. Provide all supporting workpapers and calculations.

5. Exhibit RLW-6, page 3 of 3, includes data related to "Pre-Credit Arrears." Please provide a full explanation of this heading.

6. Exhibit RLW-8, Schedule 4, Page 3 of 3, shows total net write-offs as comprised of net write-offs and LICAP. Please explain why LICAP expenses are included in this number and why the Company feels that these costs should be factored into the uncollectible rate calculation.

7. Page 35, line 7 of Wynter's testimony discusses the Company's implementation of a bad debt mitigation plan. Regarding this new plan, please provide the following:

1. A copy of the bad debt mitigation plan;
2. Dates the implementation of the plan started and ended;
3. A cost-benefit analysis of the plan;
4. A breakout of costs of the plan, by component, by month beginning 1/1/08 – 2/28/10.

Response:

1. a. Please see Attachment 1 for the update through February 2010 of RLW-5.

b. Please see Attachment 2 which is an update of RLW-6 Sheet 3 of 3 through February 2010. The monthly unallocated net write-offs can be seen in the leftmost section in the rows titled, "Net W-Off (Monthly)." The monthly allocated net write-offs to Electric and Gas are shown in the rightmost section in the rows titled, "Gas Net W-Off" and "Elect Net W-Off."

2. The "Normalized Bad Debt Write-Off Amounts" in the RLW exhibits do not include a component of anticipated additional net write-offs and/or increases in the reserve for bad debts. The normalization is fully explained in footnotes (1) and (2) of Attachment 1 and Attachment 2 herein, as well as in the testimony of Rudolph L. Wynter on page 39 of 53, lines 1-8.

3. The LICAP arrears forgiveness amounts have been allocated the exact same way in Case 10-E-0050 as they were in Case 08-G-0609: 72/28%, electric/gas. This is best illustrated in the work papers, Exhibit__(RLW-8), Schedule 4, Pages 1 – 3. The row toward the bottom titled, "Net W-Off & LICAP" is the summation of the top two rows on those pages. The bottom rows, "Gas Net W-Off" and "Elect Net W-Off" are respectively 28% and 72% of the "Net W-Off & LICAP" row. These two rows carry through to the rightmost section of RLW-6, Sheet 3 of 3 in the rows titled, "Gas Net W-Off 12-Mo Rolling" and "Elect Net W-Off 12-Mo Rolling." As indicated in 1b above, RLW-6 Sheet 3 of 3 has been updated here as Attachment 2.

4. See # 3 above. The 72/28% electric/gas allocation of the LICAP arrears forgiveness is no different than the treatment given in Case 08-G-0609. Net write-offs (exclusive of LICAP arrears forgiveness) and the reserve for uncollectible accounts have been booked to bad debt expense along this 72/28% allocation for over ten years. The basis of this allocation stems originally from a study for the *Gas Multi-Year Rate and Restructuring Proposal* of March 11, 1999. Attachment 3 contains pages 36 and 46 from Appendix F of that proposal. There have been some studies of gross write-off within the last several years that have not shown a significant deviation from the 72/28% allocation. Although LICAP arrears forgiveness is technically booked 100% to electric distribution, for

ratemaking purposes the Company has chosen (as it did in Case 08-G-0609) to recognize the practical reality that many LICAP customers are dual service customers who participate in the energy efficiency services of the program such as weatherization.

5. The term "Pre-Credit Arrears" refers to accounts receivable arrears exclusive of excess credits. In simple terms, excess credits are amounts owed to customers by the Company in excess of any money owed by the customer. These credits exist for a variety of reasons. In some system reports these credits are netted with the 30-day arrears dollars, thereby reducing the total arrears in that bucket. From a collections management perspective, these credits are usually not considered part of managed arrears, but generally are included in high-level tracking of total accounts receivable. In fiscal year 2009, these credits had an average monthly total of under $12 million (electric and gas). In fiscal year 2010, these credits have an average monthly total of just under $15 million (electric and gas).

6. The LICAP dollars imbedded within the net write-off figures only refer to the arrears forgiveness amounts of qualified LICAP customers. The arrears forgiveness component of LICAP has always been treated as a write-off of a receivable. These dollars are directly booked to the bad debt expense account. No other components of the LICAP program are included within the Company's net write-off figures.

7.1 Collectively, the plan constitutes the documents contained within Attachment 4.

7.2. The first phase of the Bad Debt Mitigation Plan was implemented during the mid-year of calendar 2008 with the other phases implemented afterward. The entire program is ongoing.

7.3

	Field Visits	**Outbound Calling**	**Account Initiative**	**Predictive Analytics**	**Total**
FY09 Cost					
NG NY	1,650	1,975	150	200	3,975
FY09 Reduction to Bad Debt					
NG NY	1,700	2,600	200	2,500	7,000
FY10 Cost					
NG NY	1,473	1,798	150	200	3,621

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FY10 Reduction to Bad Debt										
NG NY		6,175		7,000		525		6,500		20,200

7.4. Please see Attachment 5 to this response.

Name of Respondent: Date of Reply:

Paul S. Leo March 16, 2010

Niagara Mohawk Power Corporation
d/b/a National Grid
Case 10-E-0050
Attachment 1 to AAE-10 #1a
Witness: Rudolph L. Wynter
Sheet 1 of 2

UNCOLLECTIBLE RATE CALCULATION

GAS

Rolling 12-Mo Ending
($000's)

	31-Oct-06	30-Nov-06	31-Dec-06	31-Jan-07	28-Feb-07	31-Mar-07	30-Apr-07	31-May-07	30-Jun-07	31-Jul-07	31-Aug-07	30-Sep-07
Normalized Bad Debt Net Write-Off	$ 13,749.9	$ 14,302.5	$ 14,898.1	$ 15,261.2	$ 15,248.3	$ 15,348.3	$ 15,436.2	$ 15,308.1	$ 15,075.2	$ 15,226.2	$ 15,836.5	$ 16,215.2
Total Tariff Revenue	$ 891,898.2	$ 878,024.3	$ 830,074.6	$ 782,548.1	$ 785,157.8	$ 791,205.3	$ 801,743.7	$ 809,620.1	$ 806,061.5	$ 805,170.0	$ 803,710.1	$ 800,639.0
Late Payment Revenue	$ 3,579.5	$ 3,560.8	$ 3,479.5	$ 3,391.9	$ 3,258.2	$ 3,248.2	$ 3,288.3	$ 3,422.6	$ 3,365.4	$ 3,384.2	$ 3,371.7	$ 3,380.9
POR Receivable Revenue	$ 93,113.3	$ 99,714.4	$ 91,992.8	$ 86,629.1	$ 90,056.9	$ 94,363.5	$ 99,451.6	$ 102,890.5	$ 103,840.7	$ 104,587.6	$ 105,173.1	$ 105,421.5
	$ 988,591.0	$ 981,299.5	$ 925,547.0	$ 872,569.1	$ 878,472.9	$ 888,817.0	$ 904,483.6	$ 915,933.2	$ 913,267.6	$ 913,141.8	$ 912,254.9	$ 909,441.5
Uncollectible Rate	**1.3909%**	**1.4575%**	**1.6097%**	**1.7490%**	**1.7358%**	**1.7268%**	**1.7066%**	**1.6713%**	**1.6507%**	**1.6675%**	**1.7360%**	**1.7830%**

	31-Oct-07	30-Nov-07	31-Dec-07	31-Jan-08	29-Feb-08	31-Mar-08	30-Apr-08	31-May-08	30-Jun-08	31-Jul-08	31-Aug-08	30-Sep-08
Normalized Bad Debt Net Write-Off	$ 16,218.4	$ 15,941.2	$ 15,656.5	$ 15,574.6	$ 15,655.8	$ 15,525.1	$ 15,403.2	$ 15,436.1	$ 15,427.0	$ 15,600.2	$ 16,006.3	$ 16,008.5
Total Tariff Revenue	$ 793,945.8	$ 783,423.2	$ 799,293.5	$ 814,751.0	$ 806,178.3	$ 789,455.0	$ 787,747.6	$ 784,589.2	$ 798,099.1	$ 806,684.2	$ 813,784.0	$ 816,646.0
Late Payment Revenue	$ 3,390.5	$ 3,351.7	$ 3,329.6	$ 3,318.4	$ 3,356.8	$ 3,303.6	$ 3,311.4	$ 3,273.3	$ 3,331.2	$ 3,378.0	$ 3,427.7	$ 3,467.9
POR Receivable Revenue	$ 105,295.7	$ 106,605.7	$ 111,542.6	$ 118,346.6	$ 120,721.2	$ 122,329.2	$ 125,096.3	$ 125,346.3	$ 128,440.0	$ 130,272.5	$ 132,460.9	$ 134,350.9
	$ 902,632.0	$ 893,380.6	$ 914,165.7	$ 936,416.0	$ 930,256.2	$ 915,087.7	$ 916,155.3	$ 913,208.9	$ 929,870.3	$ 940,334.7	$ 949,672.7	$ 954,464.8
Uncollectible Rate	**1.7968%**	**1.7844%**	**1.7127%**	**1.6632%**	**1.6830%**	**1.6966%**	**1.6813%**	**1.6903%**	**1.6590%**	**1.6590%**	**1.6855%**	**1.6772%**

	31-Oct-08	30-Nov-08	31-Dec-08	31-Jan-09	28-Feb-09	31-Mar-09	30-Apr-09	31-May-09	30-Jun-09	31-Jul-09	31-Aug-09	30-Sep-09
Normalized Bad Debt Net Write-Off	$ 16,095.1	$ 16,704.2	$ 16,705.3	$ 17,564.1	$ 18,136.0	$ 18,584.5	$ 19,121.9	$ 19,465.7	$ 20,022.2	$ 20,372.7	$ 20,425.7	(1) $ 20,582.3
Total Tariff Revenue	$ 820,359.9	$ 826,763.2	$ 820,863.3	$ 839,607.5	$ 848,499.4	$ 837,487.4	$ 819,734.1	$ 803,816.6	$ 785,426.2	$ 775,087.7	$ 767,827.2	$ 763,533.7
Late Payment Revenue	$ 3,493.2	$ 3,551.2	$ 3,616.3	$ 3,712.2	$ 3,801.7	$ 3,859.5	$ 3,951.0	$ 3,893.1	$ 3,820.9	$ 3,796.6	$ 3,707.3	$ 3,637.4
POR Receivable Revenue	$ 140,933.9	$ 143,915.8	$ 148,686.0	$ 159,256.8	$ 168,279.2	$ 169,933.9	$ 168,444.5	$ 166,677.3	$ 162,960.1	$ 160,654.9	$ 158,229.2	$ 156,282.9
	$ 964,786.9	$ 974,230.2	$ 973,165.6	$ 1,002,576.5	$ 1,020,580.2	$ 1,011,280.7	$ 992,129.6	$ 974,387.0	$ 952,207.2	$ 939,539.2	$ 929,763.8	$ 923,454.0
Uncollectible Rate	**1.6683%**	**1.7146%**	**1.7166%**	**1.7519%**	**1.7770%**	**1.8377%**	**1.9274%**	**1.9977%**	**2.1027%**	**2.1684%**	**2.1969%**	**2.2288%**

	31-Oct-09	30-Nov-09	31-Dec-09	31-Jan-10	28-Feb-10	31-Mar-10	30-Apr-10	31-May-10	30-Jun-10	31-Jul-10	31-Aug-10	30-Sep-10
Normalized Bad Debt Net Write-Off	(2) $ 21,441.6	(2) $ 21,211.4	$ 20,966.8	$ 20,394.5	$ 19,963.4							
Total Tariff Revenue	$ 763,769.7	$ 757,565.1	$ 730,782.2	$ 703,008.1	$ 681,183.9							
Late Payment Revenue	$ 3,594.9	$ 3,537.0	$ 3,542.1	$ 3,405.9	$ 3,266.7							
POR Receivable Revenue	$ 150,195.2	$ 146,768.9	$ 139,006.2	$ 130,365.0	$ 122,297.0							
	$ 917,559.8	$ 907,871.0	$ 873,330.5	$ 836,779.0	$ 806,747.6							
Uncollectible Rate	**2.3368%**	**2.3364%**	**2.4008%**	**2.4373%**	**2.4745%**							

ELECTRIC

Rolling 12-Mo Ending
($000's)

	31-Oct-06	30-Nov-06	31-Dec-06	31-Jan-07	28-Feb-07	31-Mar-07	30-Apr-07	31-May-07	30-Jun-07	31-Jul-07	31-Aug-07	30-Sep-07
Normalized Bad Debt Net Write-Off	$ 35,356.8	$ 36,777.7	$ 38,309.4	$ 39,243.1	$ 39,209.8	$ 39,467.2	$ 39,693.0	$ 39,363.7	$ 38,764.8	$ 39,153.2	$ 40,722.5	$ 41,696.2
Total Tariff Revenue	$ 3,109,634.5	$ 3,123,264.5	$ 3,120,084.3	$ 3,099,545.0	$ 3,107,068.6	$ 3,126,469.3	$ 3,137,065.0	$ 3,160,279.9	$ 3,180,254.0	$ 3,186,818.8	$ 3,177,717.4	$ 3,185,562.5
Late Payment Revenue	$ 14,595.0	$ 14,475.3	$ 14,442.9	$ 14,626.6	$ 14,610.3	$ 14,584.5	$ 14,653.0	$ 14,904.2	$ 14,764.8	$ 15,044.6	$ 15,000.5	$ 15,182.4
POR Receivable Revenue	$ 74,553.1	$ 88,687.3	$ 105,072.6	$ 120,311.5	$ 139,595.5	$ 161,586.6	$ 180,023.6	$ 196,902.3	$ 204,293.3	$ 210,789.1	$ 214,904.4	$ 221,971.6
	$ 3,198,782.6	$ 3,226,427.2	$ 3,239,599.9	$ 3,234,483.1	$ 3,261,274.4	$ 3,302,640.4	$ 3,331,741.7	$ 3,372,086.4	$ 3,399,312.1	$ 3,412,652.4	$ 3,407,622.3	$ 3,422,716.5
Uncollectible Rate	**1.1053%**	**1.1399%**	**1.1825%**	**1.2133%**	**1.2023%**	**1.1950%**	**1.1914%**	**1.1673%**	**1.1404%**	**1.1473%**	**1.1950%**	**1.2182%**

	31-Oct-07	30-Nov-07	31-Dec-07	31-Jan-08	29-Feb-08	31-Mar-08	30-Apr-08	31-May-08	30-Jun-08	31-Jul-08	31-Aug-08	30-Sep-08
Normalized Bad Debt Net Write-Off	$ 41,704.4	$ 40,991.6	$ 40,259.5	$ 40,048.9	$ 40,257.9	$ 39,921.7	$ 39,608.3	$ 39,692.9	$ 39,669.4	$ 40,114.9	$ 41,159.0	$ 41,164.7
Total Tariff Revenue	$ 3,199,056.9	$ 3,205,204.7	$ 3,217,611.9	$ 3,244,370.3	$ 3,229,360.2	$ 3,193,809.1	$ 3,180,093.4	$ 3,164,302.2	$ 3,146,291.3	$ 3,142,311.6	$ 3,162,777.6	$ 3,153,304.5
Late Payment Revenue	$ 15,559.5	$ 15,719.5	$ 15,701.0	$ 15,744.3	$ 15,960.3	$ 15,959.3	$ 16,074.9	$ 15,879.2	$ 16,172.7	$ 16,198.7	$ 16,224.0	$ 16,145.6
POR Receivable Revenue	$ 230,083.4	$ 236,243.0	$ 244,588.5	$ 259,160.3	$ 267,066.4	$ 271,559.9	$ 279,622.9	$ 287,859.5	$ 297,057.4	$ 313,254.6	$ 331,374.4	$ 339,505.0
	$ 3,444,699.9	$ 3,457,167.2	$ 3,477,901.5	$ 3,519,274.9	$ 3,512,386.9	$ 3,481,328.3	$ 3,475,791.2	$ 3,468,040.9	$ 3,459,521.4	$ 3,471,764.9	$ 3,510,376.1	$ 3,508,955.0
Uncollectible Rate	**1.2107%**	**1.1857%**	**1.1576%**	**1.1380%**	**1.1462%**	**1.1467%**	**1.1395%**	**1.1445%**	**1.1467%**	**1.1555%**	**1.1725%**	**1.1731%**

	31-Oct-08	30-Nov-08	31-Dec-08	31-Jan-09	28-Feb-09	31-Mar-09	30-Apr-09	31-May-09	30-Jun-09	31-Jul-09	31-Aug-09	30-Sep-09
												(1)
Normalized Bad Debt Net Write-Off	$ 41,387.3	$ 42,953.7	$ 42,956.6	$ 45,164.9	$ 46,635.5	$ 47,788.6	$ 49,170.7	$ 50,054.7	$ 51,485.6	$ 52,386.9	$ 52,523.1	$ 52,925.8
Total Tariff Revenue	$ 3,133,055.0	$ 3,112,613.5	$ 3,091,280.7	$ 3,081,245.9	$ 3,076,984.3	$ 3,060,266.1	$ 3,028,875.3	$ 2,998,174.9	$ 2,950,238.7	$ 2,912,193.9	$ 2,849,751.4	$ 2,834,349.1
Late Payment Revenue	$ 15,932.6	$ 15,962.9	$ 16,147.2	$ 16,405.2	$ 16,322.3	$ 16,276.4	$ 16,420.3	$ 16,242.7	$ 15,798.3	$ 15,740.2	$ 15,356.5	$ 14,943.8
POR Receivable Revenue	$ 343,639.7	$ 346,877.1	$ 348,210.4	$ 349,756.9	$ 352,276.4	$ 349,087.9	$ 343,409.7	$ 336,950.9	$ 327,739.9	$ 312,052.6	$ 294,037.8	$ 287,904.5
	$ 3,492,627.3	$ 3,475,453.5	$ 3,455,638.3	$ 3,447,408.0	$ 3,445,583.0	$ 3,425,630.5	$ 3,388,705.3	$ 3,351,368.5	$ 3,293,776.8	$ 3,239,986.7	$ 3,159,145.6	$ 3,137,197.5
Uncollectible Rate	**1.1850%**	**1.2359%**	**1.2431%**	**1.3101%**	**1.3535%**	**1.3950%**	**1.4510%**	**1.4936%**	**1.5631%**	**1.6169%**	**1.6626%**	**1.6870%**

	31-Oct-09	30-Nov-09	31-Dec-09	31-Jan-10	28-Feb-10	31-Mar-10	30-Apr-10	31-May-10	30-Jun-10	31-Jul-10	31-Aug-10	30-Sep-10
	(2)	(2)										
Normalized Bad Debt Net Write-Off	$ 55,135.6	$ 54,543.7	$ 53,914.5	$ 52,443.1	$ 51,334.4							
Total Tariff Revenue	$ 2,830,718.7	$ 2,824,630.1	$ 2,824,675.0	$ 2,837,570.5	$ 2,844,630.0							
Late Payment Revenue	$ 14,793.9	$ 14,431.8	$ 14,570.3	$ 14,345.3	$ 14,280.1							
POR Receivable Revenue	$ 285,287.5	$ 284,009.1	$ 282,672.0	$ 285,682.9	$ 286,552.7							
	$ 3,130,800.1	$ 3,123,071.0	$ 3,121,917.2	$ 3,137,598.8	$ 3,145,462.7							
Uncollectible Rate	**1.7611%**	**1.7465%**	**1.7270%**	**1.6714%**	**1.6320%**							

(1) For the month of Sept '09, total electric & gas net write-off has been normalized by removing about $4.1 million that had been inadvertently accelerated to write-off due to a system issue. These amounts would have been written off during Oct '09 and Nov '09.

(2) For the months of Oct&Nov '09, total electric & gas net write-off has been increased by the allocated portion of the $4.1 million that had been inadvertently accelerated in Sept'09 due to a system issue.
Also, written off during Oct '09 was another $1.5 accelerated amount that should have gone to Nov '09. Both Oct09 & Nov09 have been normalized by the additional figure.

12-Mo Rolling Avg., AR & Arrears; 12-Mo Rolling Net Write-Off (E&G)
($000's)

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Net W-Off (Monthly)	3,780	1,998	3,129	1,913	2,392	1,297	7,299	5,582	5,011	4,542	4,165	3,526
12-mo Rolling Net W-Off	45,452	45,237	43,820	43,406	43,947	41,873	44,477	44,648	44,343	44,645	44,927	44,633
Pre-Credit Arrears (Mo-End)	163,726	178,854	186,751	197,950	201,682	199,960	184,836	181,510	170,634	168,117	177,037	171,989
Arrears (Rolling 12 Avg.)	171,724	172,522	172,380	172,665	173,398	174,405	175,623	176,917	177,929	179,066	180,324	181,920
Accnts Receivable (Mo-End)	443,719	458,952	453,739	441,080	408,422	378,992	393,449	372,223	383,670	361,405	369,203	450,680
A/R (Rolling 12 Avg.)	382,227	379,924	382,192	382,545	383,043	384,979	388,336	391,657	395,175	398,881	403,004	409,628

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
Net W-Off (Monthly)	4,044	2,010	3,208	2,081	3,784	4,810	3,621	4,930	6,325	6,603	6,138	5,653
12-mo Rolling Net W-Off	44,897	44,909	44,988	45,155	46,547	50,061	46,383	45,731	47,045	49,107	51,080	53,208
Pre-Credit Arrears (Mo-End)	197,581	204,906	214,820	232,114	241,077	218,606	212,584	213,074	201,657	200,983	197,651	191,142
Arrears (Rolling 12 Avg.)	184,742	186,913	189,252	192,099	195,382	196,936	199,248	201,878	204,464	207,202	208,920	210,516
Accnts Receivable (Mo-End)	504,756	500,704	506,460	494,967	439,978	420,977	437,287	420,920	409,129	375,394	374,371	424,600
A/R (Rolling 12 Avg.)	414,714	418,194	422,587	427,078	429,707	433,206	436,859	440,917	443,039	444,205	444,635	442,462

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
Net W-Off (Monthly)	5,341	1,964	3,566	2,394	3,327	3,978	4,160	7,110	7,677	6,615	5,148	4,637
12-mo Rolling Net W-Off	54,504	54,458	54,816	55,129	54,672	53,840	54,379	56,559	57,911	57,923	56,933	55,916
Pre-Credit Arrears (Mo-End)	207,119	205,426	221,545	244,739	261,307	246,270	252,427	233,114	226,007	220,339	218,569	214,452
Arrears (Rolling 12 Avg.)	211,311	211,355	211,915	212,967	214,653	216,958	220,278	221,948	223,978	225,591	227,334	229,276
Accnts Receivable (Mo-End)	445,210	515,967	540,131	551,167	480,895	490,647	481,147	470,917	477,018	410,181	418,800	484,715
A/R (Rolling 12 Avg.)	437,500	438,772	441,578	446,261	449,671	455,477	459,132	463,298	468,955	471,854	475,557	480,566

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
Net W-Off (Monthly)	5,048	2,254	3,099	1,959	3,444	3,946	4,779	8,560	7,685	6,924	7,324	4,641
12-mo Rolling Net W-Off	55,623	55,914	55,447	55,012	55,129	55,096	55,715	57,165	57,173	57,482	59,658	59,662
Pre-Credit Arrears (Mo-End)	237,284	256,641	266,184	288,897	308,605	286,431	290,278	273,529	272,313	268,382	255,221	268,346
Arrears (Rolling 12 Avg.)	231,790	236,058	239,778	243,458	247,399	250,746	253,900	257,268	261,127	265,131	268,185	272,676
Accnts Receivable (Mo-End)	549,663	586,227	585,678	594,809	544,504	545,388	526,077	527,702	516,706	441,745	472,468	529,623
A/R (Rolling 12 Avg.)	489,271	495,126	498,921	502,558	507,859	512,421	516,165	520,897	524,204	526,835	531,307	535,049

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Net W-Off (Monthly)	8,116	4,296	4,700	3,879	4,672	5,933	6,031	8,749	8,244	9,993	6,501	3,767
12-mo Rolling Net W-Off	62,729	64,772	66,373	68,293	69,520	71,508	72,760	72,949	73,508	76,577	75,755	74,881
Pre-Credit Arrears (Mo-End)	270,118	293,236	318,905	319,968	318,393	302,179	285,414	277,365	267,251	253,667	257,162	254,441
Arrears (Rolling 12 Avg.)	275,412	278,462	282,855	285,444	286,260	287,572	287,167	287,487	287,065	285,839	286,000	284,842
Accnts Receivable (Mo-End)	606,641	630,459	581,757	552,463	521,857	467,476	476,875	482,725	437,218	422,299	449,202	459,007
A/R (Rolling 12 Avg.)	539,797	543,483	543,157	539,628	537,740	531,248	527,148	523,399	516,776	515,155	513,216	507,332
									(1)	(2)	(2)	

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Net W-Off (Monthly)	6,072	2,756										
12-mo Rolling Net W-Off	72,838	71,298										
Pre-Credit Arrears (Mo-End)	268,380	267,481										
Arrears (Rolling 12 Avg.)	284,697	284,217										
Accnts Receivable (Mo-End)	578,114	604,440										
A/R (Rolling 12 Avg.)	504,954	502,766										

12-Mo Rolling Net Write-Off (E&G Allocated)
($000's)

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Gas Net W-Off	1,058	559	876	536	670	363	2,044	1,563	1,403	1,272	1,166	987
Gas Net W-Off 12-Mo Rolling	12,726	12,666	12,270	12,154	12,305	11,724	12,454	12,501	12,416	12,500	12,580	12,497
Elect Net W-Off	2,722	1,439	2,253	1,378	1,722	934	5,255	4,019	3,608	3,270	2,999	2,539
Elect Net W-Off 12-Mo Rolling	32,725	32,571	31,550	31,252	31,642	30,148	32,024	32,146	31,927	32,144	32,347	32,136

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
Gas Net W-Off	1,132	563	898	583	1,060	1,347	1,014	1,380	1,771	1,849	1,719	1,583
Gas Net W-Off 12-Mo Rolling	12,571	12,575	12,597	12,644	13,033	14,017	12,987	12,605	13,173	13,750	14,302	14,898
Elect Net W-Off	2,912	1,447	2,310	1,498	2,725	3,463	2,607	3,550	4,554	4,754	4,420	4,070
Elect Net W-Off 12-Mo Rolling	32,328	32,334	32,391	32,512	33,514	36,044	33,395	32,926	33,873	35,357	36,778	38,309

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
Gas Net W-Off	1,495	550	998	670	931	1,114	1,165	1,991	2,150	1,852	1,441	1,298
Gas Net W-Off 12-Mo Rolling	15,261	15,248	15,348	15,436	15,308	15,075	15,226	15,837	16,215	16,218	15,941	15,656
Elect Net W-Off	3,846	1,414	2,567	1,724	2,395	2,864	2,995	5,119	5,528	4,763	3,707	3,338
Elect Net W-Off 12-Mo Rolling	39,243	39,210	39,467	39,693	39,364	38,765	39,153	40,722	41,696	41,704	40,992	40,260

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
Gas Net W-Off	1,414	631	868	549	964	1,105	1,338	2,397	2,152	1,939	2,051	1,299
Gas Net W-Off 12-Mo Rolling	15,575	15,656	15,525	15,403	15,436	15,427	15,600	16,006	16,008	16,095	16,704	16,705
Elect Net W-Off	3,635	1,623	2,231	1,411	2,480	2,841	3,441	6,163	5,533	4,985	5,273	3,341
Elect Net W-Off 12-Mo Rolling	40,049	40,258	39,922	39,608	39,693	39,669	40,115	41,159	41,165	41,387	42,954	42,957

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Gas Net W-Off	2,272	1,203	1,316	1,086	1,308	1,661	1,689	2,450	2,308	2,798	1,820	1,055
Gas Net W-Off 12-Mo Rolling	17,564	18,136	18,584	19,122	19,466	20,022	20,373	20,426	20,582	21,442	21,211	20,967
Elect Net W-Off	5,843	3,093	3,384	2,793	3,364	4,272	4,342	6,299	5,936	7,195	4,681	2,712
Elect Net W-Off 12-Mo Rolling	45,165	46,636	47,789	49,171	50,055	51,486	52,387	52,523	52,926	55,136	54,544	53,915
									(1)	(2)	(2)	

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Gas Net W-Off	1,700	772										
Gas Net W-Off 12-Mo Rolling	20,395	19,963										
Elect Net W-Off	4,372	1,985										
Elect Net W-Off 12-Mo Rolling	52,443	51,334										

(1) For the month of Sept '09, total electric & gas net write-off has been normalized by removing about $4.1 million that had been inadvertently accelerated to write-off due to a system issue. These amounts would have been written off during Oct '09 and Nov '09.

(2) For the months of Oct&Nov '09, total electric & gas net write-off has been increased by the allocated portion of the $4.1 million that had been inadvertently accelerated in Sept'09 due to a system issue.
Also, written off during Oct '09 was another $1.5 accelerated amount that should have gone to Nov '09. Both Oct09 & Nov09 have been normalized by the additional figure.

Correction of Bad Debt Expenses

It is the preferred Company policy to directly charge expenses between electric and gas accounts whenever an actual breakdown of costs can be determined. When an actual breakdown of costs is not known, a standard pre-determined allocation is applied.

In late 1996, the Company sold all of its receivables to NM Receivables, Inc. (and continues to sell all of its receivables on an ongoing basis). Prior to the sale of receivables to NMR, Niagara Mohawk recorded all Bad Debt expenses based on the preferred Company policy which reflected a composite electric and gas allocation derived from the actual write-offs of all customer accounts. Subsequent to the inception of NMR and continuing through the end of the historic test period, the Company applied the standard corporate allocation (17%) for all Bad Debt write-offs when it should have been using the preferred method of allocation.

The Company has since recognized this error and effective with January 1999 business, will book all Bad Debt expenses using the composite gas allocation of twenty-eight percent (28%). This composite allocation approximates past results and was derived from the actual write-offs of all customer accounts for the period twelve months ending December 31, 1998 as shown on Workpaper G-2.

Based on this correction, which is summarized on Workpaper G-3, the Company expects to incur $10,080,000 of Bad Debt expenses in 1999 compared to $6,524,000 in the historic test period or a total increase of $3,556,000. The Company is not proposing any further adjustments beyond this 1999 correction and is forecasting the same level of write-offs throughout the settlement period adjusted only for inflation.

Line of Credit Fees

The Company's current Bank Facility Agreement (BFA) expires in June 2000 (extended one year beyond its original June, 1999 expiration). The BFA is an extraordinary financing transaction that is necessary for the Company to continue to provide safe, reliable utility service across its franchise territory. Without proper financing, the Company could experience unacceptable cost increases in securing labor and materials required to service its customers. To insure the continuation of reliable service, the Company believes that it is reasonable to assume that there will be some form of a Bank Facility Agreement throughout the proposed settlement period but also recognizes that the costs should decrease as a function of the Company's improved credit rating. As summarized on Workpaper G-3, the Company expects to reduce BFA costs from the historic test year level of $1,432,000 to $898,000 in the year 2000, or a total reduction of $534,000. The Company is not proposing any further adjustments beyond the Year 2000 and is forecasting the same level of BFA costs throughout the settlement period, adjusted only for inflation.

Date of Request: March 5, 2010
Due Date: May 20, 2010

Request No. AAE-10 OG May
NMPC Req. No. NM 177 DPS 107

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Allison Esposito

TO: Rudolph L. Wynter Jr.

Request:

1. Please update Exhibit RLW-5 for electric data from 10/1/09 – 2/28/10. In addition to the 12-month average rolling data provided in this exhibit, provide the actual write-offs on a monthly stand alone basis. Please provide monthly updates of this exhibit through the end of the rate case.

Response:

Please see Attachments #1a and #1b.

Name of Respondent: Paul S. Leo

Date of Reply: June 17, 2010

Form 103

UNCOLLECTIBLE RATE CALCULATION

GAS

Rolling 12-Mo Ending
($000's)

	31-Oct-06	30-Nov-06	31-Dec-06	31-Jan-07	28-Feb-07	31-Mar-07	30-Apr-07	31-May-07	30-Jun-07	31-Jul-07	31-Aug-07	30-Sep-07
Normalized Bad Debt Net Write-Off	$ 13,749.9	$ 14,302.5	$ 14,898.1	$ 15,261.2	$ 15,248.3	$ 15,348.3	$ 15,436.2	$ 15,308.1	$ 15,075.2	$ 15,226.2	$ 15,836.5	$ 16,215.2
Total Tariff Revenue	$ 891,898.2	$ 878,024.3	$ 830,074.6	$ 782,548.1	$ 785,157.8	$ 791,205.3	$ 801,743.7	$ 809,620.1	$ 806,061.5	$ 805,170.0	$ 803,710.1	$ 800,639.0
Late Payment Revenue	$ 3,579.5	$ 3,560.8	$ 3,479.5	$ 3,391.9	$ 3,258.2	$ 3,248.2	$ 3,288.3	$ 3,422.6	$ 3,365.4	$ 3,384.2	$ 3,371.7	$ 3,380.9
POR Receivable Revenue	$ 93,113.3	$ 99,714.4	$ 91,992.8	$ 86,629.1	$ 90,056.9	$ 94,363.5	$ 99,451.6	$ 102,890.5	$ 103,840.7	$ 104,587.6	$ 105,173.1	$ 105,421.5
	$ 988,591.0	$ 981,299.5	$ 925,547.0	$ 872,569.1	$ 878,472.9	$ 888,817.0	$ 904,483.6	$ 915,933.2	$ 913,267.6	$ 913,141.8	$ 912,254.9	$ 909,441.5
Uncollectible Rate	**1.3909%**	**1.4575%**	**1.6097%**	**1.7490%**	**1.7358%**	**1.7268%**	**1.7066%**	**1.6713%**	**1.6507%**	**1.6675%**	**1.7360%**	**1.7830%**

	31-Oct-07	30-Nov-07	31-Dec-07	31-Jan-08	29-Feb-08	31-Mar-08	30-Apr-08	31-May-08	30-Jun-08	31-Jul-08	31-Aug-08	30-Sep-08
Normalized Bad Debt Net Write-Off	$ 16,218.4	$ 15,941.2	$ 15,656.5	$ 15,574.6	$ 15,655.8	$ 15,525.1	$ 15,403.2	$ 15,436.1	$ 15,427.0	$ 15,600.2	$ 16,006.3	$ 16,008.5
Total Tariff Revenue	$ 793,945.8	$ 783,423.2	$ 799,293.5	$ 814,751.0	$ 806,178.3	$ 789,455.0	$ 787,747.6	$ 784,589.2	$ 798,099.1	$ 806,684.2	$ 813,784.0	$ 816,646.0
Late Payment Revenue	$ 3,390.5	$ 3,351.7	$ 3,329.6	$ 3,318.4	$ 3,356.8	$ 3,303.6	$ 3,311.4	$ 3,273.3	$ 3,331.2	$ 3,378.0	$ 3,427.7	$ 3,467.9
POR Receivable Revenue	$ 105,295.7	$ 106,605.7	$ 111,542.6	$ 118,346.6	$ 120,721.2	$ 122,329.2	$ 125,096.3	$ 125,346.3	$ 128,440.0	$ 130,272.5	$ 132,460.9	$ 134,350.9
	$ 902,632.0	$ 893,380.6	$ 914,165.7	$ 936,416.0	$ 930,256.2	$ 915,087.7	$ 916,155.3	$ 913,208.9	$ 929,870.3	$ 940,334.7	$ 949,672.7	$ 954,464.8
Uncollectible Rate	**1.7968%**	**1.7844%**	**1.7127%**	**1.6632%**	**1.6830%**	**1.6966%**	**1.6813%**	**1.6903%**	**1.6590%**	**1.6590%**	**1.6855%**	**1.6772%**

	31-Oct-08	30-Nov-08	31-Dec-08	31-Jan-09	28-Feb-09	31-Mar-09	30-Apr-09	31-May-09	30-Jun-09	31-Jul-09	31-Aug-09	30-Sep-09
												(1)
Normalized Bad Debt Net Write-Off	$ 16,095.1	$ 16,704.2	$ 16,705.3	$ 17,564.1	$ 18,136.0	$ 18,584.5	$ 19,121.9	$ 19,465.7	$ 20,022.2	$ 20,372.7	$ 20,425.7	$ 20,582.3
Total Tariff Revenue	$ 820,359.9	$ 826,763.2	$ 820,863.3	$ 839,607.5	$ 848,499.4	$ 837,487.4	$ 819,734.1	$ 803,816.6	$ 785,426.2	$ 775,087.7	$ 767,827.2	$ 763,533.7
Late Payment Revenue	$ 3,493.2	$ 3,551.2	$ 3,616.3	$ 3,712.2	$ 3,801.7	$ 3,859.5	$ 3,951.0	$ 3,893.1	$ 3,820.9	$ 3,796.6	$ 3,707.3	$ 3,637.4
POR Receivable Revenue	$ 140,933.9	$ 143,915.8	$ 148,686.0	$ 159,256.8	$ 168,279.2	$ 169,933.9	$ 168,444.5	$ 166,677.3	$ 162,960.1	$ 160,654.9	$ 158,229.2	$ 156,282.9
	$ 964,786.9	$ 974,230.2	$ 973,165.6	$ 1,002,576.5	$ 1,020,580.2	$ 1,011,280.7	$ 992,129.6	$ 974,387.0	$ 952,207.2	$ 939,539.2	$ 929,763.8	$ 923,454.0
Uncollectible Rate	**1.6683%**	**1.7146%**	**1.7166%**	**1.7519%**	**1.7770%**	**1.8377%**	**1.9274%**	**1.9977%**	**2.1027%**	**2.1684%**	**2.1969%**	**2.2288%**

	31-Oct-09	30-Nov-09	31-Dec-09	31-Jan-10	28-Feb-10	31-Mar-10	30-Apr-10	31-May-10	30-Jun-10	31-Jul-10	31-Aug-10	30-Sep-10
	(2)	(2)										
Normalized Bad Debt Net Write-Off	$ 21,441.6	$ 21,211.4	$ 20,966.8	$ 20,394.5	$ 19,963.4	$ 19,147.3	$ 18,293.2	$ 17,712.2				
Total Tariff Revenue	$ 763,769.7	$ 757,565.1	$ 730,782.2	$ 703,008.1	$ 681,183.9	$ 666,195.7	$ 649,333.3	$ 648,898.4				
Late Payment Revenue	$ 3,594.9	$ 3,537.0	$ 3,542.1	$ 3,405.9	$ 3,266.7	$ 3,247.8	$ 3,038.9	$ 2,972.1				
POR Receivable Revenue	$ 150,195.2	$ 146,768.9	$ 139,006.2	$ 130,365.0	$ 122,297.0	$ 117,496.2	$ 111,943.6	$ 111,393.1				
	$ 917,559.8	$ 907,871.0	$ 873,330.5	$ 836,779.0	$ 806,747.6	$ 786,939.6	$ 764,315.8	$ 763,263.6				
Uncollectible Rate	**2.3368%**	**2.3364%**	**2.4008%**	**2.4373%**	**2.4745%**	**2.4331%**	**2.3934%**	**2.3206%**				

ELECTRIC

Rolling 12-Mo Ending
($000's)

	31-Oct-06	30-Nov-06	31-Dec-06	31-Jan-07	28-Feb-07	31-Mar-07	30-Apr-07	31-May-07	30-Jun-07	31-Jul-07	31-Aug-07	30-Sep-07
Normalized Bad Debt Net Write-Off	$ 35,356.8	$ 36,777.7	$ 38,309.4	$ 39,243.1	$ 39,209.8	$ 39,467.2	$ 39,693.0	$ 39,363.7	$ 38,764.8	$ 39,153.2	$ 40,722.5	$ 41,696.2
Total Tariff Revenue	$ 3,109,634.5	$ 3,123,264.5	$ 3,120,084.3	$ 3,099,545.0	$ 3,107,068.6	$ 3,126,469.3	$ 3,137,065.0	$ 3,160,279.9	$ 3,180,254.0	$ 3,186,818.8	$ 3,177,717.4	$ 3,185,562.5
Late Payment Revenue	$ 14,595.0	$ 14,475.3	$ 14,442.9	$ 14,626.6	$ 14,610.3	$ 14,584.5	$ 14,653.0	$ 14,904.2	$ 14,764.8	$ 15,044.6	$ 15,000.5	$ 15,182.4
POR Receivable Revenue	$ 74,553.1	$ 88,687.3	$ 105,072.6	$ 120,311.5	$ 139,595.5	$ 161,586.6	$ 180,023.6	$ 196,902.3	$ 204,293.3	$ 210,789.1	$ 214,904.4	$ 221,971.6
	$ 3,198,782.6	$ 3,226,427.2	$ 3,239,599.9	$ 3,234,483.1	$ 3,261,274.4	$ 3,302,640.4	$ 3,331,741.7	$ 3,372,086.4	$ 3,399,312.1	$ 3,412,652.4	$ 3,407,622.3	$ 3,422,716.5
Uncollectible Rate	**1.1053%**	**1.1399%**	**1.1825%**	**1.2133%**	**1.2023%**	**1.1950%**	**1.1914%**	**1.1673%**	**1.1404%**	**1.1473%**	**1.1950%**	**1.2182%**

	31-Oct-07	30-Nov-07	31-Dec-07	31-Jan-08	29-Feb-08	31-Mar-08	30-Apr-08	31-May-08	30-Jun-08	31-Jul-08	31-Aug-08	30-Sep-08
Normalized Bad Debt Net Write-Off	$ 41,704.4	$ 40,991.6	$ 40,259.5	$ 40,048.9	$ 40,257.9	$ 39,921.7	$ 39,608.3	$ 39,692.9	$ 39,669.4	$ 40,114.9	$ 41,159.0	$ 41,164.7
Total Tariff Revenue	$ 3,199,056.9	$ 3,205,204.7	$ 3,217,611.9	$ 3,244,370.3	$ 3,229,360.2	$ 3,193,809.1	$ 3,180,093.4	$ 3,164,302.2	$ 3,146,291.3	$ 3,142,311.6	$ 3,162,777.6	$ 3,153,304.5
Late Payment Revenue	$ 15,559.5	$ 15,719.5	$ 15,701.0	$ 15,744.3	$ 15,960.3	$ 15,959.3	$ 16,074.9	$ 15,879.2	$ 16,172.7	$ 16,198.7	$ 16,224.0	$ 16,145.6
POR Receivable Revenue	$ 230,083.4	$ 236,243.0	$ 244,588.5	$ 259,160.3	$ 267,066.4	$ 271,559.9	$ 279,622.9	$ 287,859.5	$ 297,057.4	$ 313,254.6	$ 331,374.4	$ 339,505.0
	$ 3,444,699.9	$ 3,457,167.2	$ 3,477,901.5	$ 3,519,274.9	$ 3,512,386.9	$ 3,481,328.3	$ 3,475,791.2	$ 3,468,040.9	$ 3,459,521.4	$ 3,471,764.9	$ 3,510,376.1	$ 3,508,955.0
Uncollectible Rate	**1.2107%**	**1.1857%**	**1.1576%**	**1.1380%**	**1.1462%**	**1.1467%**	**1.1395%**	**1.1445%**	**1.1467%**	**1.1555%**	**1.1725%**	**1.1731%**

	31-Oct-08	30-Nov-08	31-Dec-08	31-Jan-09	28-Feb-09	31-Mar-09	30-Apr-09	31-May-09	30-Jun-09	31-Jul-09	31-Aug-09	30-Sep-09
												(1)
Normalized Bad Debt Net Write-Off	$ 41,387.3	$ 42,953.7	$ 42,956.6	$ 45,164.9	$ 46,635.5	$ 47,788.6	$ 49,170.7	$ 50,054.7	$ 51,485.6	$ 52,386.9	$ 52,523.1	$ 52,925.8
Total Tariff Revenue	$ 3,133,055.0	$ 3,112,613.5	$ 3,091,280.7	$ 3,081,245.9	$ 3,076,984.3	$ 3,060,266.1	$ 3,028,875.3	$ 2,998,174.9	$ 2,950,238.7	$ 2,912,193.9	$ 2,849,751.4	$ 2,834,349.1
Late Payment Revenue	$ 15,932.6	$ 15,962.9	$ 16,147.2	$ 16,405.2	$ 16,322.3	$ 16,276.4	$ 16,420.3	$ 16,242.7	$ 15,798.3	$ 15,740.2	$ 15,356.5	$ 14,943.8
POR Receivable Revenue	$ 343,639.7	$ 346,877.1	$ 348,210.4	$ 349,756.9	$ 352,276.4	$ 349,087.9	$ 343,409.7	$ 336,950.9	$ 327,739.9	$ 312,052.6	$ 294,037.8	$ 287,904.5
	$ 3,492,627.3	$ 3,475,453.5	$ 3,455,638.3	$ 3,447,408.0	$ 3,445,583.0	$ 3,425,630.5	$ 3,388,705.3	$ 3,351,368.5	$ 3,293,776.8	$ 3,239,986.7	$ 3,159,145.6	$ 3,137,197.5
Uncollectible Rate	**1.1850%**	**1.2359%**	**1.2431%**	**1.3101%**	**1.3535%**	**1.3950%**	**1.4510%**	**1.4936%**	**1.5631%**	**1.6169%**	**1.6626%**	**1.6870%**

	31-Oct-09	30-Nov-09	31-Dec-09	31-Jan-10	28-Feb-10	31-Mar-10	30-Apr-10	31-May-10	30-Jun-10	31-Jul-10	31-Aug-10	30-Sep-10
	(2)	(2)										
Normalized Bad Debt Net Write-Off	$ 55,135.6	$ 54,543.7	$ 53,914.5	$ 52,443.1	$ 51,334.4	$ 49,235.9	$ 47,039.7	$ 45,545.5				
Total Tariff Revenue	$ 2,830,718.7	$ 2,824,630.1	$ 2,824,675.0	$ 2,837,570.5	$ 2,844,630.0	$ 2,875,640.5	$ 2,901,351.0	$ 2,918,745.7				
Late Payment Revenue	$ 14,793.9	$ 14,431.8	$ 14,570.3	$ 14,345.3	$ 14,280.1	$ 14,373.4	$ 14,068.0	$ 14,095.5				
POR Receivable Revenue	$ 285,287.5	$ 284,009.1	$ 282,672.0	$ 285,682.9	$ 286,552.7	$ 290,639.6	$ 292,910.3	$ 296,946.4				
	$ 3,130,800.1	$ 3,123,071.0	$ 3,121,917.2	$ 3,137,598.8	$ 3,145,462.7	$ 3,180,653.5	$ 3,208,329.3	$ 3,229,787.6				
Uncollectible Rate	**1.7611%**	**1.7465%**	**1.7270%**	**1.6714%**	**1.6320%**	**1.5480%**	**1.4662%**	**1.4102%**				

(1) For the month of Sept '09, total electric & gas net write-off has been normalized by removing about $4.1 million that had been inadvertently accelerated to write-off due to a system issue. These amounts would have been written off during Oct '09 and Nov '09.

(2) For the months of Oct&Nov '09, total electric & gas net write-off has been increased by the allocated portion of

the $4.1 million that had been inadvertently accelerated in Sept'09 due to a system issue.
Also, written off during Oct '09 was another $1.5 accelerated amount that should have gone to Nov '09. Both Oct09 & Nov09 have been normalized by the additional figure.

Niagara Mohawk Power Corporation
d/b/a National Grid
Case 10-E-0050
Attachment 2 to AAE-10 #1b
Witness: Rudolph L. Wynter
Sheet 1 of 1

12-Mo Rolling Avg., AR & Arrears; 12-Mo Rolling Net Write-Off (E&G)
($000's)

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Net W-Off (Monthly)	3,780	1,998	3,129	1,913	2,392	1,297	7,299	5,582	5,011	4,542	4,165	3,526
12-mo Rolling Net W-Off	45,452	45,237	43,820	43,406	43,947	41,873	44,477	44,648	44,343	44,645	44,927	44,633
Pre-Credit Arrears (Mo-End)	163,726	178,854	186,751	197,950	201,682	199,960	184,836	181,510	170,634	168,117	177,037	171,989
Arrears (Rolling 12 Avg.)	171,724	172,522	172,380	172,665	173,398	174,405	175,623	176,917	177,929	179,066	180,324	181,920
Accnts Receivable (Mo-End)	443,719	458,952	453,739	441,080	408,422	378,992	393,449	372,223	383,670	361,405	369,203	450,680
A/R (Rolling 12 Avg.)	382,227	379,924	382,192	382,545	383,043	384,979	388,336	391,657	395,175	398,881	403,004	409,628

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
Net W-Off (Monthly)	4,044	2,010	3,208	2,081	3,784	4,810	3,621	4,930	6,325	6,603	6,138	5,653
12-mo Rolling Net W-Off	44,897	44,909	44,988	45,155	46,547	50,061	46,383	45,731	47,045	49,107	51,080	53,208
Pre-Credit Arrears (Mo-End)	197,581	204,906	214,820	232,114	241,077	218,606	212,584	213,074	201,657	200,983	197,651	191,142
Arrears (Rolling 12 Avg.)	184,742	186,913	189,252	192,099	195,382	196,936	199,248	201,878	204,464	207,202	208,920	210,516
Accnts Receivable (Mo-End)	504,756	500,704	506,460	494,967	439,978	420,977	437,287	420,920	409,129	375,394	374,371	424,600
A/R (Rolling 12 Avg.)	414,714	418,194	422,587	427,078	429,707	433,206	436,859	440,917	443,039	444,205	444,635	442,462

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
Net W-Off (Monthly)	5,341	1,964	3,566	2,394	3,327	3,978	4,160	7,110	7,677	6,615	5,148	4,637
12-mo Rolling Net W-Off	54,504	54,458	54,816	55,129	54,672	53,840	54,379	56,559	57,911	57,923	56,933	55,916
Pre-Credit Arrears (Mo-End)	207,119	205,426	221,545	244,739	261,307	246,270	252,427	233,114	226,007	220,339	218,569	214,452
Arrears (Rolling 12 Avg.)	211,311	211,355	211,915	212,967	214,653	216,958	220,278	221,948	223,978	225,591	227,334	229,276
Accnts Receivable (Mo-End)	445,210	515,967	540,131	551,167	480,895	490,647	481,147	470,917	477,018	410,181	418,800	484,715
A/R (Rolling 12 Avg.)	437,500	438,772	441,578	446,261	449,671	455,477	459,132	463,298	468,955	471,854	475,557	480,566

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
Net W-Off (Monthly)	5,048	2,254	3,099	1,959	3,444	3,946	4,779	8,560	7,685	6,924	7,324	4,641
12-mo Rolling Net W-Off	55,623	55,914	55,447	55,012	55,129	55,096	55,715	57,165	57,173	57,482	59,658	59,662
Pre-Credit Arrears (Mo-End)	237,284	256,641	266,184	288,897	308,605	286,431	290,278	273,529	272,313	268,382	255,221	268,346
Arrears (Rolling 12 Avg.)	231,790	236,058	239,778	243,458	247,399	250,746	253,900	257,268	261,127	265,131	268,185	272,676
Accnts Receivable (Mo-End)	549,663	586,227	585,678	594,809	544,504	545,388	526,077	527,702	516,706	441,745	472,468	529,623
A/R (Rolling 12 Avg.)	489,271	495,126	498,921	502,558	507,859	512,421	516,165	520,897	524,204	526,835	531,307	535,049

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Net W-Off (Monthly)	8,116	4,296	4,700	3,879	4,672	5,933	6,031	8,749	8,244	9,993	6,501	3,767
12-mo Rolling Net W-Off	62,729	64,772	66,373	68,293	69,520	71,508	72,760	72,949	73,508	76,577	75,755	74,881
Pre-Credit Arrears (Mo-End)	270,118	293,236	318,905	319,968	318,393	302,179	285,414	277,365	267,251	253,667	257,162	254,441
Arrears (Rolling 12 Avg.)	275,412	278,462	282,855	285,444	286,260	287,572	287,167	287,487	287,065	285,839	286,000	284,842
Accnts Receivable (Mo-End)	606,641	630,459	581,757	552,463	521,857	467,476	476,875	482,725	437,218	422,299	449,202	459,007
A/R (Rolling 12 Avg.)	539,797	543,483	543,157	539,628	537,740	531,248	527,148	523,399	516,776	515,155	513,216	507,332
									(1)	(2)	(2)	

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Net W-Off (Monthly)	6,072	2,756	1,786	828	2,597							
12-mo Rolling Net W-Off	72,838	71,298	68,383	65,333	63,258							
Pre-Credit Arrears (Mo-End)	268,380	287,481	297,652	315,890	302,842							
Arrears (Rolling 12 Avg.)	284,697	284,217	282,446	282,106	280,810							
Accnts Receivable (Mo-End)	578,114	604,440	564,176	552,914	525,021							
A/R (Rolling 12 Avg.)	504,954	502,786	501,321	501,359	501,622							

12-Mo Rolling Net Write-Off (E&G Allocated)
($000's)

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Gas Net W-Off	1,058	559	876	536	670	363	2,044	1,563	1,403	1,272	1,166	987
Gas Net W-Off 12-Mo Rolling	12,726	12,666	12,270	12,154	12,305	11,724	12,454	12,501	12,416	12,500	12,580	12,497
Elect Net W-Off	2,722	1,439	2,253	1,378	1,722	934	5,255	4,019	3,608	3,270	2,999	2,539
Elect Net W-Off 12-Mo Rolling	32,725	32,571	31,550	31,252	31,642	30,148	32,024	32,146	31,927	32,144	32,347	32,136

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
Gas Net W-Off	1,132	563	898	583	1,060	1,347	1,014	1,380	1,771	1,849	1,719	1,583
Gas Net W-Off 12-Mo Rolling	12,571	12,575	12,597	12,644	13,033	14,017	12,967	12,805	13,173	13,750	14,302	14,898
Elect Net W-Off	2,912	1,447	2,310	1,498	2,725	3,463	2,607	3,550	4,554	4,754	4,420	4,070
Elect Net W-Off 12-Mo Rolling	32,326	32,334	32,391	32,512	33,514	36,044	33,395	32,926	33,873	35,357	36,778	38,309

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
Gas Net W-Off	1,495	550	998	670	931	1,114	1,165	1,991	2,150	1,852	1,441	1,298
Gas Net W-Off 12-Mo Rolling	15,261	15,248	15,348	15,436	15,308	15,075	15,226	15,837	16,215	16,218	15,941	15,656
Elect Net W-Off	3,846	1,414	2,567	1,724	2,395	2,864	2,995	5,119	5,528	4,763	3,707	3,338
Elect Net W-Off 12-Mo Rolling	39,243	39,210	39,467	39,693	39,364	38,765	39,153	40,722	41,696	41,704	40,992	40,260

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
Gas Net W-Off	1,414	631	868	549	964	1,105	1,338	2,397	2,152	1,939	2,051	1,299
Gas Net W-Off 12-Mo Rolling	15,575	15,656	15,525	15,403	15,436	15,427	15,600	16,006	16,008	16,095	16,704	16,705
Elect Net W-Off	3,635	1,623	2,231	1,411	2,480	2,841	3,441	6,163	5,533	4,985	5,273	3,341
Elect Net W-Off 12-Mo Rolling	40,049	40,258	39,922	39,608	39,693	39,669	40,115	41,159	41,165	41,387	42,954	42,957

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Gas Net W-Off	2,272	1,203	1,316	1,086	1,308	1,661	1,689	2,450	2,308	2,798	1,820	1,055
Gas Net W-Off 12-Mo Rolling	17,564	18,136	18,584	19,122	19,466	20,022	20,373	20,426	20,582	21,442	21,211	20,967
Elect Net W-Off	5,843	3,093	3,384	2,793	3,364	4,272	4,342	6,299	5,936	7,195	4,681	2,712
Elect Net W-Off 12-Mo Rolling	45,165	46,636	47.789	49,171	50,055	51,486	52,387	52,523	52,926	55,136	54,544	53,915
									(1)	(2)	(2)	

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Gas Net W-Off	1,700	772	500	232	727							
Gas Net W-Off 12-Mo Rolling	20,395	19,963	19,147	18,293	17,712							
Elect Net W-Off	4,372	1,985	1,266	596	1,870							
Elect Net W-Off 12-Mo Rolling	52,443	51,334	49,236	47,040	45,546							

(1) For the month of Sept '09, total electric & gas net write-off has been normalized by removing about $4.1 million that had been inadvertently accelerated to write-off due to a system issue. These amounts would have been written off during Oct '09 and Nov '09.

(2) For the months of Oct&Nov '09, total electric & gas net write-off has been increased by the allocated portion of the $4.1 million that had been inadvertently accelerated in Sept'09 due to a system issue.
Also, written off during Oct '09 was another $1.5 accelerated amount that should have gone to Nov '09. Both Oct09 & Nov09 have been normalized by the additional figure.

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. DAG-2
NMPC Req. No. NM 179 DPS 109

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO:

Request:

Follow-up to I/R #NM-28 (RAV-14).
In a format similar to the response to I/R #NM-28 (RAV-14), please provide the following information for each VERO employee that was a former NMPC employee; whether that employee either remained a NMPC employee; or whether, at some point, was transferred into the National Grid USA Service Co.

A. VERO employee's name;

B. The date of employee's retirement and salary at time of retirement;

C. Provide the costs of the employee being VERO'ed by type of cost.

D. Has the Company ever incurred costs associated with the same employee subsequent to the employee retiring? If yes, from the date of retirement up to the present time, please provide, in an Excel spreadsheet, the following information by calendar year:

1. Number of hours the VERO employee worked for the Company as a contracted employee;
2. Incurred costs for VERO employee's contractor services;
3. Incurred costs for VERO employee's travel expenses;
4. Incurred costs for VERO employee's lodging expenses;
5. Any other incurred costs for VERO employee;
6. Total costs incurred for VERO employee.

E. Indicate whether the above costs were charged to capital or expense, along with the reason for such accounting.

F. Indicate the date the VERO employee first performed contractor services for the Company.

Form 103

G. Indicate if VERO employee is still a contracted employee; if not, indicate the last date that the employee performed contractor services for the Company.

Response:

Request A is subject to a Protective Order.
Please see Attachment 1 for responses to requests B, C, E, F and G.
Please see Attachment 2 for responses to request D.

Name of Respondent:	Date of Reply:
Ed Considine	March 22, 2010

Redacted Version

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. DAG-2
NMPC Req. No. NM 179 DPS 109

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO:

Request:

Follow-up to I/R #NM-28 (RAV-14).
In a format similar to the response to I/R #NM-28 (RAV-14), please provide the following information for each VERO employee that was a former NMPC employee; whether that employee either remained a NMPC employee; or whether, at some point, was transferred into the National Grid USA Service Co.

A. VERO employee's name;

B. The date of employee's retirement and salary at time of retirement;

C. Provide the costs of the employee being VERO'ed by type of cost.

D. Has the Company ever incurred costs associated with the same employee subsequent to the employee retiring? If yes, from the date of retirement up to the present time, please provide, in an Excel spreadsheet, the following information by calendar year:

1. Number of hours the VERO employee worked for the Company as a contracted employee;
2. Incurred costs for VERO employee's contractor services;
3. Incurred costs for VERO employee's travel expenses;
4. Incurred costs for VERO employee's lodging expenses;
5. Any other incurred costs for VERO employee;
6. Total costs incurred for VERO employee.

E. Indicate whether the above costs were charged to capital or expense, along with the reason for such accounting.

F. Indicate the date the VERO employee first performed contractor services for the Company.

Form 103

G. Indicate if VERO employee is still a contracted employee; if not, indicate the last date that the employee performed contractor services for the Company.

Response:

Request A is subject to a Protective Order.
Please see Attachment 1 for responses to requests B, C, E, F and G.
Please see Attachment 2 for responses to request D.

Name of Respondent:	Date of Reply:
Ed Considine	March 22, 2010

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100029829	04/01/2002	71,801.60	27,336					
[redacted]	100022486	04/01/2002	55,201.12	64,719					
[redacted]	100032620	04/01/2002	61,100.00	70,030					
[redacted]	100022470	04/01/2002	60,401.12	82,958					
[redacted]	100030170	04/01/2002	43,700.80	85,696					
[redacted]	100031800	04/01/2002	73,900.32	90,954					
[redacted]	100031985	04/01/2002	75,200.32	92,554					
[redacted]	100031293	04/01/2002	69,101.76	92,907					
[redacted]	100022820	04/01/2002	76,100.96	93,663					
[redacted]	100021978	04/01/2002	78,700.96	96,863					
[redacted]	100031593	04/01/2002	65,902.00	100,418					
[redacted]	100023113	04/01/2002	82,600.96	101,663					
[redacted]	100028279	04/01/2002	87,201.92	107,325					
[redacted]	100026556	04/01/2002	68,500.64	124,052	7,513				
[redacted]	100027108	04/01/2002	48,002.24	148,691					
[redacted]	100024168	04/01/2002	124,901.92	153,725					
[redacted]	100028272	04/01/2002	62,601.76	178,166	13,408				
[redacted]	100033203	04/01/2002	66,100.32	179,798					
[redacted]	100024167	04/01/2002	45,000.80	242,303	3,987				
[redacted]	100032922	04/01/2002	70,102.24	243,798	13,662				
[redacted]	100027723	04/01/2002	59,300.80	272,062	1,602				
[redacted]	100028271	04/01/2002	82,401.28	282,880	3,396				
[redacted]	100032567	04/01/2002	79,401.92	289,841	3,396				
[redacted]	100032082	04/01/2002	75,701.60	290,197	4,679				
[redacted]	100032569	04/01/2002	59,101.12	292,983	3,854				
[redacted]	100027035	04/01/2002	65,000.00	294,126	1,911				
[redacted]	100031300	04/01/2002	67,901.60	298,097	534				
[redacted]	100028179	04/01/2002	65,800.80	299,078	2,547				
[redacted]	100029911	04/01/2002	68,400.80	316,502	3,064				
[redacted]	100031803	04/01/2002	80,901.60	334,439	534				
[redacted]	100030654	04/01/2002	75,901.28	347,652	4,282				
[redacted]	100021577	04/01/2002	107,101.28	180,000					
[redacted]	100027051	04/01/2002	289,500.64	180,000					
[redacted]	100032785	04/01/2002	177,001.76	180,000	12,637				
[redacted]	100026867	04/01/2002	93,200.64	180,000					
[redacted]	100028190	04/01/2002	66,601.60	180,000	5,667				
[redacted]	100025545	04/01/2002	73,101.60	180,000	4,930				
[redacted]	100026639	04/01/2002	38,702.56	180,000					
[redacted]	100031532	04/01/2002	41,701.92	180,000					
[redacted]	100029643	04/01/2002	39,700.96	180,000					

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100023268	04/01/2002	42,001.44	180,000					
[redacted]	100029741	04/01/2002	61,800.96	180,000	3,737				
[redacted]	100025116	04/01/2002	89,600.16	180,000					
[redacted]	100023618	04/01/2002	42,900.00	180,000					
[redacted]	100027872	04/01/2002	49,000.64	180,000					
[redacted]	100023138	04/01/2002	54,000.96	180,000					
[redacted]	100023123	04/01/2002	60,101.60	180,000					
[redacted]	100032563	04/01/2002	92,901.12	180,000		08/02/2005	01/28/2007	Expense	Performed Operations & Maintenance activities
[redacted]	100026882	04/01/2002	41,400.32	180,000					
[redacted]	100026361	04/01/2002	54,701.92	180,000					
[redacted]	100026663	04/01/2002	42,800.16	180,000					
[redacted]	100023518	04/01/2002	63,700.00	180,000	7,513				
[redacted]	100032957	04/01/2002	74,301.76	180,000					
[redacted]	100033449	04/01/2002	42,900.00	180,000					
[redacted]	100022401	04/01/2002	67,801.76	180,000					
[redacted]	100027874	04/01/2002	44,200.00	180,000					
[redacted]	100028191	04/01/2002	41,202.72	180,000	534				
[redacted]	100029822	04/01/2002	98,500.48	180,000	1,217	04/23/2007	05/10/2009	Capital	Assisted in processing capital work orders
[redacted]	100028603	04/01/2002	43,388.80	180,000					
[redacted]	100024741	04/01/2002	66,601.60	180,000					
[redacted]	100025099	04/01/2002	71,801.60	180,000	10,763				
[redacted]	100033040	04/01/2002	178,000.16	180,000					
[redacted]	100023848	04/01/2002	73,301.28	180,000	608				
[redacted]	100024776	04/01/2002	68,500.64	180,000	13,662				
[redacted]	100032103	04/01/2002	66,901.12	180,000					
[redacted]	100026742	04/01/2002	60,201.44	180,000	9,860				
[redacted]	100023586	04/01/2002	75,100.48	180,000	3,987				
[redacted]	100022749	04/01/2002	70,301.92	180,000					
[redacted]	100023139	04/01/2002	62,002.72	180,000					
[redacted]	100021520	04/01/2002	83,301.92	180,000	2,972				
[redacted]	100031739	04/01/2002	128,202.88	180,000					
[redacted]	100030937	04/01/2002	75,300.16	180,000	9,860				
[redacted]	100023037	04/01/2002	72,196.80	180,000					
[redacted]	100023273	04/01/2002	113,803.04	180,000					
[redacted]	100021498	04/01/2002	189,300.80	180,000					
[redacted]	100022483	04/01/2002	81,000.00	180,000					
[redacted]	100027174	04/01/2002	80,704.00	180,000		04/19/2007	06/28/2009	Expense	Performed Operations & Maintenance activities
[redacted]	100030362	04/01/2002	61,100.00	180,000	2,547				
[redacted]	100022527	04/01/2002	43,702.88	180,000					
[redacted]	100023656	04/01/2002	55,100.00	180,000	5,432				

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
Attachment 1 - Confidential

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100029332	04/01/2002	67,801.76	180,000					
	100031736	04/01/2002	81,201.12	180,000					
	100030257	04/01/2002	65,601.12	180,000					
	100029738	04/01/2002	77,101.44	180,000	4,805				
	100031911	04/01/2002	54,400.32	180,000					
	100029931	04/01/2002	186,201.60	180,000					
	100025610	04/01/2002	46,800.00	180,000					
	100021567	04/01/2002	67,200.64	180,000					
	100027177	04/01/2002	53,601.60	180,000	10,156				
	100032608	04/01/2002	112,600.80	180,000					
	100029739	04/01/2002	65,301.60	180,000	11,770				
	100032909	04/01/2002	89,100.96	180,000	5,386				
	100033246	04/01/2002	66,701.44	180,000					
	100023964	04/01/2002	68,101.28	180,000					
	100030863	04/01/2002	53,000.48	180,000	5,205				
	100026234	04/01/2002	56,001.92	180,000					
	100022088	04/01/2002	75,200.00	180,000	10,362				
	100025575	04/01/2002	69,700.80	180,000					
	100030348	04/01/2002	66,000.48	180,000					
	100026591	05/01/2002	41,500.16	40,830					
	100033230	05/01/2002	62,601.76	62,130					
	100025540	05/01/2002	42,600.48	170,483	14,956				
	100030163	05/01/2002	99,401.00	181,760					
	100022468	05/01/2002	65,000.00	225,635	4,271				
	100032566	05/01/2002	88,501.92	228,083					
	100026752	05/01/2002	47,700.64	242,634	4,167				
	100031289	05/01/2002	48,201.92	255,089	5,219				
	100030676	05/01/2002	47,700.64	180,000					
	100023852	05/01/2002	67,901.60	180,000	1,274				
	100026545	05/01/2002	93,801.76	180,000					
	100023524	05/01/2002	47,800.48	180,000					
	100029820	05/01/2002	59,092.80	180,000					
	100031306	05/01/2002	46,901.92	180,000					
	100029143	05/01/2002	61,703.20	180,000	1,217				
	100033096	05/01/2002	54,901.60	180,000					
	100025702	05/01/2002	96,990.40	180,000	8,914				
	100024727	05/01/2002	66,200.16	180,000					
	100031741	05/01/2002	67,701.92	180,000					
	100021869	05/01/2002	65,501.28	180,000					
	100028295	05/01/2002	71,801.60	180,000					

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100031903	05/01/2002	66,601.60	180,000	2,670				
	100022099	05/01/2002	74,201.92	180,000					
	100027180	05/01/2002	74,000.16	180,000		07/05/2004	Still employed	Expense	Performed Telecommunications Support activities
	100031731	05/01/2002	67,073.96	180,000	608				
	100028313	05/01/2002	71,000.00	180,000					
	100021552	05/01/2002	83,401.76	180,000	9,494				
	100022282	06/01/2002	104,900.64	129,119					
	100022520	06/01/2002	88,801.44	132,644					
	100025681	06/01/2002	67,901.60	165,776	8,510				
	100028397	06/01/2002	76,100.96	309,138	2,450	02/24/2003	Still employed	Capital	Assisted in closing out capital work orders
	100022402	06/01/2002	85,500.48	180,000					
	100033082	06/01/2002	65,601.12	180,000					
	100031112	06/01/2002	91,800.80	180,000					
	100033044	06/01/2002	78,101.92	180,000	4,919				
	100021836	06/01/2002	69,401.28	180,000					
	100021868	06/01/2002	86,600.80	180,000	849				
	100022193	06/01/2002	70,601.44	180,000	212	11/27/2006	07/30/2008	Expense	Performed Customer Billing Activities
	100024797	06/01/2002	85,001.28	180,000					
	100025387	06/01/2002	93,500.16	180,000					
	100025120	06/01/2002	73,700.64	180,000					
	100023230	06/01/2002	74,301.76	180,000					
	100026607	06/01/2002	67,100.80	180,000					
	100028956	06/01/2002	78,301.60	180,000	2,433				
	100022502	06/01/2002	65,401.44	180,000					
	100027490	06/01/2002	106,600.00	180,000					
	100025582	06/01/2002	73,301.28	180,000					
	100030158	06/01/2002	85,901.92	180,000					
	100023846	06/01/2002	68,201.12	180,000	2,123				
	100026894	06/01/2002	129,900.16	180,000					
	100029821	06/01/2002	89,300.64	180,000	6,059				
	100026871	06/01/2002	91,800.80	180,000		06/12/2002	08/20/2003	Expense	Performed Operations & Maintenance activities
	100026575	07/01/2002	71,400.16	70,310					
	100021499	07/01/2002	76,200.80	82,811					
	100022204	07/01/2002	77,800.32	96,641					
	100022223	07/01/2002	79,701.44	98,820					
	100030653	07/01/2002	67,500.16	275,304	2,123				
	100032079	07/01/2002	65,601.12	305,743	5,316				
	100032381	07/01/2002	72,800.00	331,350	6,239	11/27/2006	Still employed	Expense	Assisted in training activities
	100030347	07/01/2002	73,900.32	340,244	4,293				
	100032089	07/01/2002	84,400.16	180,000					

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
Attachment 1 - Confidential

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100022198	07/01/2002	84,901.44	180,000	7,616	01/31/2007	06/12/2007	Expense	Performed Operations & Maintenance activities
[redacted]	100026751	07/01/2002	61,800.96	180,000	11,583				
[redacted]	100028405	07/01/2002	84,100.64	180,000	8,162				
[redacted]	100022127	07/01/2002	72,200.96	180,000					
[redacted]	100025588	07/01/2002	72,101.12	180,000					
[redacted]	100022562	07/01/2002	78,201.76	180,000					
[redacted]	100026868	07/01/2002	74,201.92	180,000					
[redacted]	100023275	07/01/2002	71,100.64	180,000					
[redacted]	100032580	07/01/2002	80,000.96	180,000		11/27/2006	12/23/2008	Expense	Performed Operations & Maintenance activities
[redacted]	100025759	07/01/2002	69,201.60	180,000	13,739				
[redacted]	100023660	07/01/2002	59,987.00	180,000					
[redacted]	100022950	07/01/2002	97,500.00	180,000	1,068				
[redacted]	100026856	07/01/2002	77,001.60	180,000	425	09/26/2005	11/26/2006	Capital	Processing Electric Services capital work orders
[redacted]	100023222	07/01/2002	93,000.96	180,000					
[redacted]	100025580	07/01/2002	75,901.28	180,000	2,123				
[redacted]	100027128	07/01/2002	104,101.92	180,000					
[redacted]	100029455	07/01/2002	91,802.88	180,000					
[redacted]	100025587	07/01/2002	62,200.32	180,000	425				
[redacted]	100033177	07/01/2002	70,701.28	180,000		10/04/2004	01/11/2005	Expense	Performed Operations & Maintenance activities
[redacted]	100023661	07/01/2002	66,701.44	180,000					
[redacted]	100028188	07/01/2002	45,801.60	180,000					
[redacted]	100031833	07/01/2002	69,101.76	180,000					
[redacted]	100027516	07/01/2002	86,201.44	180,000					
[redacted]	100031111	07/01/2002	71,901.44	180,000	4,794	08/26/2002	11/24/2002	Expense	Performed Operations & Maintenance activities
[redacted]	100032766	07/01/2002	106,200.64	180,000	9,600				
[redacted]	100027163	08/01/2002	73,201.44	92,633					
[redacted]	100030265	08/01/2002	70,100.16	99,800					
[redacted]	100023107	08/01/2002	74,301.76	103,703					
[redacted]	100030256	08/01/2002	90,001.60	110,771		10/10/2002	07/23/2009	Expense	Performed Engineering Support activities
[redacted]	100025546	08/01/2002	69,800.64	227,271	2,123				
[redacted]	100027042	08/01/2002	98,700.16	425,473	3,507				
[redacted]	100022270	08/01/2002	79,801.28	180,000	3,507				
[redacted]	100032573	08/01/2002	81,300.96	180,000					
[redacted]	100033421	08/01/2002	55,201.12	180,000	3,830				
[redacted]	100029154	08/01/2002	126,900.80	180,000	6,347				
[redacted]	100028286	08/01/2002	70,301.92	180,000					
[redacted]	100029825	08/01/2002	63,500.32	180,000	5,814	09/01/2004	08/20/2009	Expense	Performed Operations & Maintenance activities
[redacted]	100021815	08/01/2002	94,400.80	180,000					
[redacted]	100021505	08/01/2002	79,501.76	180,000					
[redacted]	100028406	08/01/2002	85,001.28	180,000		10/14/2002	10/10/2003	Expense	Performed Operations & Maintenance activities

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
Attachment 1 - Confidential

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100026196	08/01/2002	74,301.76	180,000					
	100033211	09/01/2002	65,800.80	45,032					
	100022145	09/01/2002	72,600.32	80,977					
	100026266	09/01/2002	75,000.64	92,308		09/12/2005	01/11/2006	Expense	Performed Operations & Maintenance activities
	100030460	09/01/2002	75,701.60	93,171		10/10/2002	09/12/2003	Expense	Performed Operations & Maintenance activities
	100024150	09/01/2002	63,600.16	114,122					
	100022194	09/01/2002	64,101.44	130,849					
	100028611	09/01/2002	110,801.60	467,817	5,078				
	100033046	09/01/2002	62,701.60	180,000		09/17/2003	11/28/2003	Expense	Performed Operations & Maintenance activities
	100029317	10/01/2002	79,000.48	97,231		10/01/2002	04/30/2009	Expense	Performed Operations & Maintenance activities
	100031627	10/01/2002	78,000.00	268,831	3,147				
	100032225	10/01/2002	62,901.28	180,000		09/17/2003	02/20/2004	Expense	Performed Operations & Maintenance activities
	100025117	10/01/2002	97,000.80	180,000					
	100026874	10/01/2002	60,101.60	180,000					
	100024702	10/01/2002	77,001.60	180,000					
	100024177	11/01/2002	76,700.00	135,787					
	100032395	12/01/2002	86,001.76	154,867					
	100019567	12/01/2002	65,208.00	273,555	425				
	100027175	01/01/2003	76,100.96	121,828	1,846				
	100032223	01/01/2003	68,001.44	144,143					
	100033043	01/01/2003	73,800.48	235,244	4,615				
	100027032	02/01/2003	141,400.48	189,317	6,611				
	100030679	04/01/2003	72,200.96	47,879					
	100026611	04/01/2003	76,300.64	49,889		04/02/2007	12/17/2008	Expense	Assisted in security support projects
	100032289	04/01/2003	62,801.44	53,140					
	100021508	04/01/2003	73,201.44	61,940		09/26/2003	05/21/2004	Expense	Performed Operations & Maintenance activities
	100025574	05/01/2003	76,300.64	31,777					
	100025572	05/01/2003	86,401.12	106,340		05/01/2003	05/02/2003	Expense	Performed Operations & Maintenance activities
	100027886	06/01/2003	77,600.64	47,754					
	100019707	06/01/2003	57,504.00	70,774					
	100026123	06/01/2003	62,000.64	109,062		06/02/2003	07/02/2003	Expense	Performed Operations & Maintenance activities
	100019512	07/01/2003	56,700.00	60,013					
	100019431	07/01/2003	64,212.00	67,906					
	100024730	07/01/2003	87,701.12	107,940					
	100019587	07/01/2003	71,808.00	134,379					
	100019343	07/01/2003	61,800.00	142,033					
	100022746	07/01/2003	66,302.08	173,140					
	100026771	08/01/2003	96,501.60	181,366					
	100022652	09/01/2003	75,300.16	395,572	3,363				
	100033767	10/01/2003	65,904.00	81,108					

DAG-2 VERO Employees - NMPC Employee
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Niagara Mohawk Power Corporation
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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100019452	12/01/2003	76,200.80						
[redacted]	100033667	12/01/2003	70,104.00	28,871					
[redacted]	100025382	12/01/2003	80,901.60	33,241					
[redacted]	100031727	12/01/2003	57,900.96	52,295					
[redacted]	100020994	12/01/2003	47,112.00	65,155		12/06/2004	12/01/2009	Capital	Performed Gas Operations activities
[redacted]	100021058	12/01/2003	57,000.32	87,118					
[redacted]	100023407	12/01/2003	76,200.80	93,785					
[redacted]	100033671	12/01/2003	76,908.00	94,656					
[redacted]	100026057	12/01/2003	97,608.00	120,133					
[redacted]	100028002	12/01/2003	85,308.00	121,377					
[redacted]	100021385	12/01/2003	57,900.96	130,728					
[redacted]	100019398	12/01/2003	68,904.00	131,127		10/27/2008	06/04/2009	Expense	Performed Operations & Maintenance activities
[redacted]	100019363	12/01/2003	51,708.00	137,999					
[redacted]	100019376	12/01/2003	133,104.00	138,223					
[redacted]	100020699	12/01/2003	113,701.12	139,938		01/17/2010	Still employed	Expense	Performed Operations & Maintenance activities
[redacted]	100033565	12/01/2003	118,308.00	157,088					
[redacted]	100020783	12/01/2003	79,008.00	178,905					
[redacted]	100021424	12/01/2003	68,304.00	188,727					
[redacted]	100032971	12/01/2003	47,700.64	192,977	8,857	11/25/2006	11/24/2009	Expense	Performed administrative billing activities
[redacted]	100033902	12/01/2003	160,008.00	196,933					
[redacted]	100020647	12/01/2003	61,908.00	251,221					
[redacted]	100033914	12/01/2003	71,208.00	302,446	3,939	10/25/2006	11/03/2009	Expense	Performed administrative billing activities
[redacted]	100034406	12/01/2003	75,000.64	412,341	6,424				
[redacted]	100020695	12/01/2003	84,708.00	437,841	3,939	05/09/2005	12/03/2006	Capital	Performed gas construction activities
[redacted]	100033028	12/01/2003	87,804.00	457,177	1,685				
[redacted]	100023400	12/01/2003	114,408.00	559,851	3,369				
[redacted]	100020542	02/01/2004	51,600.64	20,944					
[redacted]	100019704	02/01/2004	71,808.00	74,458					
[redacted]	100019224	02/01/2004	111,864.00	137,679					
[redacted]	100020765	03/01/2004	57,804.00	95,219	2,277				
[redacted]	100019565	03/01/2004	75,804.00	175,933	1,708				
[redacted]	100019527	03/01/2004	66,000.48	260,485	5,677				
[redacted]	100032963	03/01/2004	62,100.48	328,944	3,984	03/07/2005	Still employed	Capital	Performed Gas Operations activities
[redacted]	100033026	04/01/2004	73,308.00	65,220					
[redacted]	100027682	04/01/2004	74,904.00	92,190		04/21/2004	12/31/2006	Expense	Performed Engineering Support activities
[redacted]	100031699	04/01/2004	81,108.00	96,491					
[redacted]	100024419	04/01/2004	88,200.32	101,769					
[redacted]	100029506	04/01/2004	67,608.00	103,331					
[redacted]	100019960	04/01/2004	86,208.00	106,102					
[redacted]	100019329	04/01/2004	79,512.00	106,832		04/05/2004	Still employed	Expense	Performed Operations & Maintenance activities

DAG-2 VERO Employees - NMPC Employee
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VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100025271	04/01/2004	80,808.00	111,147					
	100030127	04/01/2004	61,008.00	116,730					
	100019328	04/01/2004	111,001.28	136,615		04/05/2006	Still employed	Expense	Performed administrative tax activities
	100019204	04/01/2004	150,001.28	252,803					
	100019410	04/01/2004	83,604.00	286,442	2,277				
	100028758	04/01/2004	105,804.00	394,316	854				
	100019332	04/01/2004	74,701.12	118,780		04/14/2004	12/31/2005	Expense	Performed finance activities
	100020717	04/01/2004	63,708.00	41,655					
	100019588	05/01/2004	51,012.00	58,511					
	100019320	06/01/2004	82,301.44	106,755					
	100020543	06/01/2004	65,808.00	536,231					
	100030027	07/01/2004	80,801.76	106,323		01/29/2007	06/12/2009	Expense	Performed Operations & Maintenance activities
	100033777	07/01/2004	99,408.00	122,348					
	100031683	07/01/2004	88,608.00	484,831	1,262				
	100019585	08/01/2004	94,008.00	183,298					
	100030793	09/01/2004	67,908.00	28,025					
	100022376	09/01/2004	70,608.00	29,196					
	100034436	09/01/2004	78,204.00	56,294					
	100021790	09/01/2004	61,404.00	57,065					
	100028760	09/01/2004	69,108.00	63,792					
	100020700	09/01/2004	75,000.64	96,222					
	100029729	09/01/2004	78,312.00	96,384					
	100019531	10/01/2004	74,604.00	85,215		05/31/2005	11/26/2006	Expense	Performed Operations & Maintenance activities
	100019207	10/01/2004	126,301.76	155,446					
	100019227	10/01/2004	114,000.64	310,504					
	100019415	11/01/2004	66,204.00	27,612					
	100033955	11/01/2004	82,908.96	28,888		10/26/2009	Still employed	Capital	Performed Substation support activities
	100019562	11/01/2004	83,940.48	33,962					
	100020822	11/01/2004	67,608.00	83,981					
	100027594	11/01/2004	70,104.00	86,282					
	100034018	11/01/2004	82,908.96	102,042		10/23/2007	04/22/2008	Expense	Performed Control Center activities
	100024060	11/01/2004	85,400.04	105,108		11/04/2004	Still employed	Capital	Assisted in processing capital work orders
	100029996	11/01/2004	83,007.48	109,433		05/02/2006	08/09/2009	Capital	Performed Engineering Support activities
	100021795	11/01/2004	82,908.96	109,909		04/11/2007	05/12/2007	Expense	Performed Operations & Maintenance activities
	100019380	11/01/2004	75,000.64	110,513					
	100032098	11/01/2004	82,908.96	115,439		04/11/2007	05/12/2007	Expense	Performed Operations & Maintenance activities
	100028924	11/01/2004	97,320.00	119,778					
	100027354	11/01/2004	98,532.00	121,270					
	100020843	11/01/2004	66,504.00	166,483					
	100033899	11/01/2004	100,003.92	195,842					

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
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Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100020083	11/01/2004	84,901.44	261,394					
[redacted]	100019492	11/01/2004	67,008.00	347,360	285	12/06/2004	08/14/2009	Expense	Performed Operations & Maintenance activities
[redacted]	100019383	11/01/2004	67,008.00	369,768	569				
[redacted]	100033823	11/01/2004	80,801.76	409,641	1,622	08/30/2005	02/27/2009	Expense	Peformed training support activities
[redacted]	100019557	11/01/2004	61,800.96	105,670					
[redacted]	100020074	11/01/2004	65,208.00	109,261		02/13/2006	11/14/2008	Expense	Performed Engineering Support activities
[redacted]	100024292	10/01/2007	77,529.83	64,545					
[redacted]	100019378	10/01/2007	82,314.16	71,381					
[redacted]	100031242	10/01/2007	140,058.72	201,704					
[redacted]	100027583	10/01/2007	64,104.00	437,881	950				
[redacted]	100019581	10/01/2007	83,934.73	211,945					
[redacted]	100021564	10/01/2007	78,853.84	220,201					
[redacted]	100019234	10/01/2007	115,608.00	283,354					
[redacted]	100019211	10/01/2007	131,413.32	313,140					
[redacted]	100034201	10/01/2007	87,553.79	457,117	5,056				
[redacted]	100025808	10/01/2007	170,738.40	403,464					
[redacted]	100021049	10/01/2007	131,033.04	443,186					
[redacted]	100027335	11/01/2007	41,783.04	145,587					
[redacted]	100019524	11/01/2007	50,483.68	168,777					
[redacted]	100019439	11/01/2007	53,701.44	385,095	19,750				
[redacted]	100019497	11/01/2007	72,509.27	213,551					
[redacted]	100033756	11/01/2007	80,408.10	220,177					
[redacted]	100027804	11/01/2007	162,000.00	378,450		10/22/2008	11/19/2008	Expense	Performed gas operations support activities
[redacted]	100019244	11/01/2007	153,816.00	535,852		02/14/2008	Still employed	Expense	Worked on Human Resources administrative projects
[redacted]	100019697	12/01/2007	49,528.96	151,192					
[redacted]	100019614	12/01/2007	44,172.96	198,007	4,076				
[redacted]	100025814	12/01/2007	56,500.20	160,644					
[redacted]	100019407	12/01/2007	58,992.72	189,375					
[redacted]	100026071	12/01/2007	70,303.80	189,564					
[redacted]	100020683	12/01/2007	71,750.40	209,866					
[redacted]	100033814	12/01/2007	59,186.03	308,024	7,763				
[redacted]	100019536	12/01/2007	93,757.64	245,529					
[redacted]	100019539	12/01/2007	83,397.79	254,303					
[redacted]	100019593	12/01/2007	90,652.46	294,808					
[redacted]	100031548	12/01/2007	124,560.72	446,665	7,738				
[redacted]	100019238	12/01/2007	96,736.15	494,590	10,997				
[redacted]	100033289	12/01/2007	98,004.00	544,824	37,326				
[redacted]	100025803	01/01/2008	114,475.20	277,907		11/16/2004	Still employed	Expense	Performed administrative tax activities
[redacted]	100019478	01/01/2008	119,134.61	290,407					
[redacted]	100019116	01/01/2008	161,221.62	782,386	14,339				

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VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100028280	02/01/2008	63,718.80	364,828	12,982				
[redacted]	100025776	04/01/2008	70,810.68	89,123					
[redacted]	100020599	04/01/2008	79,380.02	174,201					
[redacted]	100019605	04/01/2008	54,531.36	369,918	5,748	05/16/2008	Still employed	Expense	Performed Engineering Support activities
[redacted]	100034374	04/01/2008	72,260.20	216,780					
[redacted]	100034299	04/01/2008	78,942.95	382,034	7,486				
[redacted]	100022071	04/01/2008	72,953.05	413,098	9,454				
[redacted]	100019245	04/01/2008	101,651.16	248,344					
[redacted]	100019438	04/01/2008	78,381.44	346,192	5,842				
[redacted]	100031011	04/01/2008	77,580.29	440,437	7,486				
[redacted]	100032856	04/01/2008	79,851.60	455,767	12,053				
[redacted]	100019251	04/01/2008	127,311.60	448,923					
[redacted]	100022273	05/01/2008	66,629.16	108,786					
[redacted]	100020926	05/01/2008	99,737.14	335,883		07/27/2009	Still employed	Expense	Worked on Human Resources administrative projects
[redacted]	100029515	06/01/2008	74,856.70	36,118					
[redacted]	100020903	06/01/2008	79,857.05	149,410		07/01/2009	Still employed	Expense	Worked on safety support activities
[redacted]	100020548	06/01/2008	89,196.79	213,270		08/17/2009	Still employed	Expense	Worked on Human Resources administrative projects
[redacted]	100024543	06/01/2008	81,462.54	214,292		09/08/2008	Still employed	Expense	Worked on training support activities
[redacted]	100019629	06/01/2008	84,286.48	349,310					
[redacted]	100019216	06/01/2008	135,330.12	609,073	4,233				
[redacted]	100019787	07/01/2008	77,579.05	129,020					
[redacted]	100033309	07/01/2008	74,991.01	212,011					
[redacted]	100021217	07/01/2008	80,992.12	224,620		05/04/2009	11/12/2009	Expense	Worked on training support activities
[redacted]	100020471	07/01/2008	93,789.01	315,990					
[redacted]	100019235	08/01/2008	89,204.41	140,713					
[redacted]	100034054	08/01/2008	91,624.36	178,683					
[redacted]	100028922	08/01/2008	80,252.02	198,840		03/02/2009	Still employed	Expense	Worked on safety support activities
[redacted]	100019219	08/01/2008	136,523.56	366,833		03/08/2010	Still employed	Capital	Assisted in processing capital work orders
[redacted]	100019508	09/01/2008	68,152.88	248,671					
[redacted]	100019423	09/01/2008	69,703.48	414,705	9,763				
[redacted]	100032189	09/01/2008	76,277.05	316,906	889				
[redacted]	100033595	10/01/2008	72,867.46	196,424					
[redacted]	100033713	10/01/2008	90,816.00	212,145					
[redacted]	100026365	10/01/2008	80,730.00	562,948	7,558	03/31/2009	Still employed	Expense	Performed Operations & Maintenance activities
[redacted]	100026698	10/01/2008	91,865.51	240,503		12/12/2008	Still employed	Expense	Performed training support activities
[redacted]	100021205	10/01/2008	91,184.12	240,841					
[redacted]	100032743	10/01/2008	91,540.74	513,203	3,119	12/14/2008	12/20/2008	Expense	Performed Operations & Maintenance activities
[redacted]	100019203	10/01/2008	115,080.14	494,620	10,176				
[redacted]	100020048	10/01/2008	191,200.00	421,724					
[redacted]	100019523	10/01/2008	87,980.09	542,868					

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
VERO Employees

Last, First & MI	Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	100019114	10/01/2008	31,464.00	939,316	8,388				
[redacted]	100019408	11/01/2008	92,402.36	239,072					
[redacted]	100021151	11/01/2008	76,067.05	440,199	1,485				
[redacted]	100021193	12/01/2008	74,088.78	212,439					
[redacted]	100026340	12/01/2008	93,394.52	244,753		02/02/2009	Still employed	Expense	Performed Operations & Maintenance activities
[redacted]	100029719	12/01/2008	86,338.62	277,458					
[redacted]	100031604	12/01/2008	83,145.18	303,454		12/15/2008	Still employed	Expense	Performed accounting support activities
[redacted]	100003205	12/01/2008	87,630.40	376,621					
[redacted]	100022355	01/01/2009	81,987.41	282,541		03/02/2009	Still employed	Expense	Worked on safety support activities
[redacted]	100021199	03/01/2009	95,131.46	138,973					
[redacted]	100019698	03/01/2009	95,220.04	140,044					
[redacted]	100034439	03/01/2009	100,304.20	164,756					
[redacted]	100028380	03/01/2009	86,800.57	183,067					
[redacted]	100023820	03/01/2009	84,800.00	188,955					
[redacted]	100031670	03/01/2009	77,159.34	209,657					
[redacted]	100019346	03/01/2009	82,307.30	288,541					
[redacted]	100019210	03/01/2009	130,906.99	680,043	20,682				
[redacted]	100022364	03/01/2009	71,196.04	119,850		09/28/2009	Still employed	Expense	Worked on Human Resources administrative projects
[redacted]	100034440	04/01/2009	82,289.22	137,412					
[redacted]	100025389	04/01/2009	74,120.86	162,375					
[redacted]	100019535	04/01/2009	80,809.39	242,194					
[redacted]	100019451	04/01/2009	173,900.00	185,409					
[redacted]	100029071	04/01/2009	81,882.61	210,920					
[redacted]	100025804	04/01/2009	75,072.19	284,909					
[redacted]	100025854	04/01/2009	79,866.12	381,636	3,790				
[redacted]	100019370	04/01/2009	88,267.99	434,211		11/01/2009	Still employed	Expense	Performed administrative tax activities
[redacted]	100024349	04/01/2009	85,837.64	464,713	2,030				
[redacted]	100019465	05/01/2009	101,590.06	327,248					
[redacted]	100034123	06/01/2009	84,820.07	229,790	9,607				
[redacted]	100019454	06/01/2009	136,435.24	402,902		09/14/2009	Still employed	Expense	Performed Operations & Maintenance activities
[redacted]	100023009	06/01/2009	86,991.06	254,018	12,306				
[redacted]	100024358	06/01/2009	86,844.44	243,194					
[redacted]	100034432	07/01/2009	214,411.64	442,389					
[redacted]	100019502	07/01/2009	98,091.10	309,107		08/03/2009	Still employed	Expense	Performed administrative finance activities
[redacted]	100019368	07/01/2009	107,646.13	542,878					
[redacted]	100032992	07/01/2009	127,551.29	327,293	3,146				
[redacted]	100034061	07/01/2009	105,811.44	211,094		07/23/2009	Still employed	Capital	Assisted in processing capital work orders
[redacted]	100028820	08/01/2009	109,903.97	265,650		09/01/2009	Still employed	Expense	Performed Operations & Maintenance activities
[redacted]	100019473	08/01/2009	85,325.65	225,850		09/24/2009	Still employed	Expense	Worked on Human Resources administrative projects
[redacted]	100019197	09/01/2009	121,726.46	304,541		10/19/2009	Still employed	Expense	Worked on collections support

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[redacted]	100021061	09/01/2009	92,287.00	113,684		10/26/2009	Still employed	Expense	Worked on billing activities
	100019611	09/01/2009	95,409.65	251,170					
	100019630	09/01/2009	50,132.16	296,700	368	03/08/2010	Still employed	Expense	Worked on Human Resources administrative projects
	100023486	10/01/2009	112,012.56	272,236		11/16/2009	Still employed	Expense	Performed administrative tax activities
	100022310	10/01/2009	102,683.62	234,356		11/02/2009	Still employed	Expense	Performed accounting support activities
	100019440	01/01/2010	83,052.12	113,806					
	100019371	01/01/2010	76,503.58	198,003					
	100019199	04/01/2010	135,255.08	198,152					
	100020977	04/01/2010	84,872.81	226,204					
	100024621	07/01/2010	82,908.00	141,804					
	100020677	08/01/2010	125,596.22	266,576					
	100021353	09/01/2010	97,753.08	232,280					
	100019519	09/01/2010	102,322.79	254,138					

* The pension costs for some of the 2002 VEROs are listed as $180,000, which is the average pension cost for the 2002 VEROs. As agreed to with the PSC, this figure was used due to missing data.

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

Annual Contract Expenses for former Employees Who Accepted a VERO

Name	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
[redacted]	100019197	Hours worked as a contractor								245	178.75
		Amount paid as a contractor								14,337.40	10,460.45
		Amount paid for air travel								0.00	0.00
		Amount paid for room and board								0.00	0.00
		All other amounts paid								0.00	0.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14,337.40	10,460.45
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100020699	Hours worked as a contractor									208
		Amount paid as a contractor									7,280.00
		Amount paid for air travel									0.00
		Amount paid for room and board									0.00
		All other amounts paid									0.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7,280.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100021061	Hours worked as a contractor								236	267
		Amount paid as a contractor								10,608.75	12,015.00
		Amount paid for air travel								0.00	0.00
		Amount paid for room and board								0.00	0.00
		All other amounts paid								0.00	0.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10,608.75	12,015.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100019454	Hours worked as a contractor								507	336
		Amount paid as a contractor								22,811.40	15,120.00
		Amount paid for air travel								0.00	0.00
		Amount paid for room and board								0.00	0.00
		All other amounts paid								251.01	0.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23,062.41	15,120.00
		Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100022198	Hours worked as a contractor						508			
	Amount paid as a contractor						20,410.00			
	Amount paid for air travel									
	Amount paid for room and board						268.03			
	All other amounts paid						430.71			
	Total amount paid	0.00	0.00	0.00	0.00	0.00	21,108.74	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100033914	Hours worked as a contractor					40	2,065	1,400	900	
	Amount paid as a contractor					1582.4	84,519.94	56,753.77	36,000.00	
	Amount paid for air travel					0.00	0.00	0.00	0.00	
	Amount paid for room and board					0.00	0.00	0.00	0.00	
	All other amounts paid					0.00	0.00	0.00	0.00	
	Total amount paid	0.00	0.00	0.00	0.00	1,582.40	84,519.94	56,753.77	36,000.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100019502	Hours worked as a contractor								821	306
	Amount paid as a contractor								33,172.17	12,356.28
	Amount paid for air travel								0.00	0.00
	Amount paid for room and board								879.03	0.00
	All other amounts paid								79.00	0.00
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34,130.20	12,356.28
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100019492	Hours worked as a contractor					2051	1,836	1,946	256	
	Amount paid as a contractor			4,505.66	59,985.57	65141.79	58,256.28	61,749.12	6,387.50	
	Amount paid for air travel					0.00	0.00	0.00	0.00	
	Amount paid for room and board					0.00	0.00	0.00	0.00	
	All other amounts paid					0.00	0.00	0.00	0.00	
	Total amount paid	0.00	0.00	4,505.66	59,985.57	65,141.79	58,256.28	61,749.12	6,387.50	0.00
	Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
[redacted]	100030256	Hours worked as a contractor					1823	1,792	1,502	874	
		Amount paid as a contractor	5,944.88	65,106.64	72,676.93	75,539.78	61407	62,720.00	52,552.50	34,960.00	
		Amount paid for air travel					0.00	0.00	0.00	0.00	
		Amount paid for room and board					0.00	3055.94	2021.03	1265.6	
		All other amounts paid					318.76	4690.66	2421.98	1610.25	
		Total amount paid	0.00	65,106.64	72,676.93	75,539.78	61,725.76	70,466.60	56,995.51	37,835.85	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100032963	Hours worked as a contractor					1,162	953	969	860	76
		Amount paid as a contractor				28,763.00	28,051.80	25,003.13	25,429.69	22,561.88	1,995.00
		Amount paid for air travel					0.00	0.00	0.00	0.00	0.00
		Amount paid for room and board					0.00	0.00	0.00	0.00	0.00
		All other amounts paid					467.50	467.5	382.50	437.00	42.50
		Total amount paid	0.00	0.00	0.00	28,763.00	28,519.30	25,470.63	25,812.19	22,998.88	2,037.50
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100027682	Hours worked as a contractor					1,696.00				
		Amount paid as a contractor			53,294.57	77,639.17	67,840.00				
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid					2,854.77				
		Total amount paid	0.00	0.00	53,294.57	77,639.17	70,694.77	0.00	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100026611	Hours worked as a contractor						49	669		
		Amount paid as a contractor						1,960.00	26,760.00		
		Amount paid for air travel						0.00	0.00		
		Amount paid for room and board						0.00	0.00		
		All other amounts paid						471.3	0.00		
		Total amount paid	0.00	0.00	0.00	0.00	0.00	2,431.30	26,760.00	0.00	0.00
		Number of round trip flights to/from Syracuse									

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
Attachment 2

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100033955	Hours worked as a contractor								300	217
	Amount paid as a contractor								10,521.88	7,595.00
	Amount paid for air travel								0.00	0.00
	Amount paid for room and board								301.71	0.00
	All other amounts paid								1,990.95	1,218.04
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12,814.54	8,813.04
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100019531	Hours worked as a contractor					222.50				
	Amount paid as a contractor				42,461.50	8,241.22				
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	0.00	0.00	42,461.50	8,241.22	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100021795	Hours worked as a contractor						26			
	Amount paid as a contractor						1,040.00			
	Amount paid for air travel						0.00			
	Amount paid for room and board						0.00			
	All other amounts paid						150.58			
	Total amount paid	0.00	0.00	0.00	0.00	0.00	1,190.58	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100028820	Hours worked as a contractor								370	57
	Amount paid as a contractor								19,536.00	3,009.60
	Amount paid for air travel								324.2	0.00
	Amount paid for room and board								1246.35	0.00
	All other amounts paid								292.7	0.00
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21,399.25	3,009.60
	Number of round trip flights to/from Syracuse								1	

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]	**Employee ID**	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100022355	Hours worked as a contractor								1,000	266
		Amount paid as a contractor								39,682.50	10,413.00
		Amount paid for air travel								0	0.00
		Amount paid for room and board								8,014.76	0.00
		All other amounts paid								8,594.60	336.23
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56,291.86	10,749.23
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100026123	Hours worked as a contractor									
		Amount paid as a contractor		1,222.21							
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid									
		Total amount paid	0.00	1,222.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100031604	Hours worked as a contractor							44	980	141
		Amount paid as a contractor							1,760.00	39,200.00	5,640.00
		Amount paid for air travel							0.00	0.00	0.00
		Amount paid for room and board							0.00	0.00	0.00
		All other amounts paid							0.00	0.00	0.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	1,760.00	39,200.00	5,640.00
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100022193	Hours worked as a contractor					110	1,108	620		
		Amount paid as a contractor					4,070.00	40,977.50	2,296.46		
		Amount paid for air travel					0.00	0.00	0.00		
		Amount paid for room and board					0.00	847.72	0.00		
		All other amounts paid					0.00	197.05	216.00		
		Total amount paid	0.00	0.00	0.00	0.00	4,070.00	42,022.27	2,512.46	0.00	0.00
		Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100026266	Hours worked as a contractor				512	32.00				
	Amount paid as a contractor				18,432.00	1,237.36				
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid				1,241.46					
	Total amount paid	0.00	0.00	0.00	19,673.46	1,237.36	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100029317	Hours worked as a contractor					1,364	1,306	1,578	399	
	Amount paid as a contractor	11,583.83	46,965.19	57,967.88	52,204.25	54,257.66	54,895.00	67,190.00	16,450.00	
	Amount paid for air travel					0.00	0.00	0.00	0.00	
	Amount paid for room and board					0.00	1,764.22	2,705.31	346.37	
	All other amounts paid					0.00	6,108.24	6,825.41	1,435.07	
	Total amount paid	0.00	46,965.19	57,967.88	52,204.25	54,257.66	62,767.46	76,720.72	18,231.44	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100026340	Hours worked as a contractor								899	243
	Amount paid as a contractor								36,840.57	9,969.38
	Amount paid for air travel								0.00	0.00
	Amount paid for room and board								559.2	0.00
	All other amounts paid								2,641.36	329.68
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40,041.13	10,299.06
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100030027	Hours worked as a contractor						1,292		785	
	Amount paid as a contractor						38,985.00		23,556.00	
	Amount paid for air travel						0.00		0.00	
	Amount paid for room and board						0.00		0.00	
	All other amounts paid						325.81		0.00	
	Total amount paid	0.00	0.00	0.00	0.00	0.00	39,310.81		23,556.00	0.00
	Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100019219	Hours worked as a contractor									No Hrs in Syster
	Amount paid as a contractor									
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100024060	Hours worked as a contractor					2107.45	1,790	1,666	484	289
	Amount paid as a contractor			6,650.00	83,164.46	84,310.00	71,600.00	66,750.00	19,346.80	11,576.80
	Amount paid for air travel					0.00	0.00	0.00	0.00	0.00
	Amount paid for room and board					0.00	2615.19	1028.08	0.00	0.00
	All other amounts paid					0.00	2489.67	2264.89	0.00	0.00
	Total amount paid	0.00	0.00	6,650.00	83,164.46	84,310.00	76,704.86	70,042.97	19,346.80	11,576.80
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100027804	Hours worked as a contractor							77		
	Amount paid as a contractor							6,120.00		
	Amount paid for air travel							0.00		
	Amount paid for room and board							0.00		
	All other amounts paid							1276		
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	7,396.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100023486	Hours worked as a contractor								208	352
	Amount paid as a contractor								10,500.00	17,831.25
	Amount paid for air travel								0.00	0.00
	Amount paid for room and board								0.00	0.00
	All other amounts paid								143.64	0.00
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10,643.64	17,831.25
	Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
[redacted]	100032563	Hours worked as a contractor				912	1,942	160			
		Amount paid as a contractor				46,000.00	89,987.50	8,000.00			
		Amount paid for air travel					0.00	0.00			
		Amount paid for room and board					1,039.92	856.60			
		All other amounts paid				22,669.67	42,617.45	2,505.91			
		Total amount paid	0.00	0.00	0.00	68,669.67	133,644.87	11,362.51	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100020926	Hours worked as a contractor								480	188
		Amount paid as a contractor								21,600.00	8,460.00
		Amount paid for air travel								0.00	0.00
		Amount paid for room and board								0.00	0.00
		All other amounts paid								0.00	0.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21,600.00	8,460.00
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100029822	Hours worked as a contractor						1,219	1,150	64	
		Amount paid as a contractor						38,173.75	41,011.25	2,248.75	
		Amount paid for air travel						0.00	0.00	0.00	
		Amount paid for room and board						0.00	0.00	0.00	
		All other amounts paid						693.62	9,980.90	198.50	
		Total amount paid	0.00	0.00	0.00	0.00	0.00	38,867.37	50,992.15	2,447.25	
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100019370	Hours worked as a contractor								190	332
		Amount paid as a contractor								9,475.00	16,637.50
		Amount paid for air travel								0.00	0.00
		Amount paid for room and board								0.00	0.00
		All other amounts paid								15.00	225.00
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9,490.00	16,862.50
		Number of round trip flights to/from Syracuse									

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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100022364	Hours worked as a contractor								485	336
	Amount paid as a contractor								16,601.55	11,501.28
	Amount paid for air travel								0.00	1846.99
	Amount paid for room and board								0.00	3040.72
	All other amounts paid								0.00	426.72
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16,601.55	16,815.71
	Number of round trip flights to/from Syracuse									5

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100026365	Hours worked as a contractor								759	112
	Amount paid as a contractor								30,337.13	4,377.75
	Amount paid for air travel								0.00	0.00
	Amount paid for room and board								2086.49	358.71
	All other amounts paid								3001.12	1391.39
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35,424.74	6,127.85
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100032580	Hours worked as a contractor					1,193	1,108	620		
	Amount paid as a contractor	16,183.70	47,680.46	66,091.93	73,521.60	46,648.25	40,977.50	2,296.46		
	Amount paid for air travel					0.00	0.00	0.00		
	Amount paid for room and board					345.36	847.72	3986.74		
	All other amounts paid					2715.53	197.05	10718.45		
	Total amount paid	0.00	47,680.46	66,091.93	73,521.60	49,709.14	42,022.27	17,001.65	0.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100020695	Hours worked as a contractor				1,117	496				
	Amount paid as a contractor				40,031.25	17,491.25				
	Amount paid for air travel					0.00				
	Amount paid for room and board					0.00				
	All other amounts paid				4,974.78	0.00				
	Total amount paid	0.00	0.00	0.00	45,006.03	17,491.25	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100020994	Hours worked as a contractor					1216	1,460	679	674	
	Amount paid as a contractor			3,074.00	25,130.00	26,700.00	29,200.00	12,570.00	14,159.25	
	Amount paid for air travel					0.00	0.00	0.00	0.00	
	Amount paid for room and board					0.00	0.00	0.00	0.00	
	All other amounts paid					0.00	0.00	0.00	0.00	
	Total amount paid	0.00	0.00	3,074.00	25,130.00	26,700.00	29,200.00	12,570.00	14,159.25	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100026856	Hours worked as a contractor				563	1,809.50				
	Amount paid as a contractor				20,807.50	66,876.25				
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid				1,705.19	12,609.07				
	Total amount paid	0.00	0.00	0.00	22,512.69	79,485.32	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100029996	Hours worked as a contractor					1386	1,632	1,573	880	
	Amount paid as a contractor					58980	67,000.00	62,920.00	36,256.00	
	Amount paid for air travel					0.00	0.00	0.00	0.00	
	Amount paid for room and board					549.25	3305.68	914.73	0.00	
	All other amounts paid					3260.06	29344.03	44176.28	18063.25	
	Total amount paid	0.00	0.00	0.00	0.00	62,789.31	99,649.71	108,011.01	54,319.25	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100027180	Hours worked as a contractor				434	759	615	678	382	35
	Amount paid as a contractor			22,832.09	13,872.00	26,565.00	21,507.50	23,730.00	13,352.50	1,225.00
	Amount paid for air travel					0.00	0.00	0.00	0.00	0.00
	Amount paid for room and board					0.00	0.00	0.00	0.00	0.00
	All other amounts paid				128.43	906.54	55.44	175.94	199.25	0.00
	Total amount paid	0.00	0.00	22,832.09	14,000.43	27,471.54	21,562.94	23,905.94	13,551.75	1,225.00
	Number of round trip flights to/from Syracuse									

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
Attachment 2

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100019398	Hours worked as a contractor							373	900	
	Amount paid as a contractor							15,180.00	36,810.00	
	Amount paid for air travel							0.00	0.00	
	Amount paid for room and board							0.00	0.00	
	All other amounts paid							0.00	0.00	
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	15,180.00	36,810.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100020548	Hours worked as a contractor								401	208
	Amount paid as a contractor								16,842.00	8,736.00
	Amount paid for air travel								0.00	0.00
	Amount paid for room and board								0.00	0.00
	All other amounts paid								0.00	0.00
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16,842.00	8,736.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100032098	Hours worked as a contractor						26			
	Amount paid as a contractor						1,040.00			
	Amount paid for air travel						0.00			
	Amount paid for room and board						0.00			
	All other amounts paid						0.00			
	Total amount paid	0.00	0.00	0.00	0.00	0.00	1,040.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100032971	Hours worked as a contractor					40	2,134	1,489	895	
	Amount paid as a contractor					1,582.40	89,320.00	59,804.83	35,800.00	
	Amount paid for air travel							1067		
	Amount paid for room and board							3,044.43		
	All other amounts paid							94.8		
	Total amount paid	0.00	0.00	0.00	0.00	1,582.40	89,320.00	64,011.06	35,800.00	0.00
	Number of round trip flights to/from Syracuse							3		

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100021217	Hours worked as a contractor								900	
	Amount paid as a contractor								$32,868	
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid								$3,626.15	
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36,494.15	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100022310	Hours worked as a contractor								304	299
	Amount paid as a contractor								18,240.00	18,464.70
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18,240.00	18,464.70
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100019332	Hours worked as a contractor									
	Amount paid as a contractor			55,520.01	20,022.10					
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	0.00	55,520.01	20,022.10	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100019605	Hours worked as a contractor							384	498	107
	Amount paid as a contractor							6,140.00	7,974.72	1,704.00
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	6,140.00	7,974.72	1,704.00
	Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100029825	Hours worked as a contractor					2076.5	1,988	1,928	781	
	Amount paid as a contractor			25,452.03	88,676.95	68,771.75	66,387.75	63,648.75	25,756.50	
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid					5614.8	197.88	390.73	43.2	
	Total amount paid	0.00	0.00	25,452.03	88,676.95	74,386.55	66,585.63	64,039.48	25,799.70	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100026698	Hours worked as a contractor							105	440	
	Amount paid as a contractor							4,553.25	17,147.13	
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid							890.44	2075.45	
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	5,443.69	19,222.58	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100032225	Hours worked as a contractor									
	Amount paid as a contractor		13,418.66	11,444.62						
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	13,418.66	11,444.62	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100025572	Hours worked as a contractor									
	Amount paid as a contractor		810.03							
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	810.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

DAG-2 VERO Employees - NMPC Employee
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Niagara Mohawk Power Corporation
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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
[redacted]	100033177	Hours worked as a contractor									
		Amount paid as a contractor			353.50	574.44					
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid									
		Total amount paid	0.00	0.00	353.50	574.44	0.00	0.00	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100019244	Hours worked as a contractor							1,307	974	167
		Amount paid as a contractor							53,106.40	31,793.76	5,333.44
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid									
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	53,106.40	31,793.76	5,333.44
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100030460	Hours worked as a contractor									
		Amount paid as a contractor	7,385.53	29,288.95							
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid									
		Total amount paid	7,385.53	29,288.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100019329	Hours worked as a contractor					2111	1,988	2,033	900	170
		Amount paid as a contractor			69,749.18	83,626.40	70,661.53	70,574.00	67,650.00	31,950.00	6,035.00
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid					2213.09	2527.74	4694.22	3886.23	398.41
		Total amount paid	0.00	0.00	69,749.18	83,626.40	72,874.62	73,101.74	72,344.22	35,836.23	6,433.41
		Number of round trip flights to/from Syracuse									

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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100021508	Hours worked as a contractor									
	Amount paid as a contractor		9,112.00	13,532.00						
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	9,112.00	13,532.00	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100019473	Hours worked as a contractor								248	392
	Amount paid as a contractor								10,168.00	16,072.00
	Amount paid for air travel									
	Amount paid for room and board								-	
	All other amounts paid								110.01	60.23
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10,278.01	16,132.23
	Number of round trip flights to/from Syracuse									
Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100032381	Hours worked as a contractor					184	868	1,607	746	344
	Amount paid as a contractor					6,440.00	33,852.00	56,245.00	29,094.00	13,416.00
	Amount paid for air travel									
	Amount paid for room and board						223.76	1,391.62		
	All other amounts paid					214.18	949.37	4,862.09	385.12	
	Total amount paid	0.00	0.00	0.00	0.00	6,654.18	35,025.13	62,498.71	29,479.12	13,416.00
	Number of round trip flights to/from Syracuse									
Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100019630	Hours worked as a contractor									No Hrs to date i
	Amount paid as a contractor									
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100034061	Hours worked as a contractor								330	202
	Amount paid as a contractor								16,475.00	10,075.00
	Amount paid for air travel									
	Amount paid for room and board									100.57
	All other amounts paid								2293.72	461.35
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18,768.72	10,636.92
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100027174	Hours worked as a contractor						1,352	483	900	
	Amount paid as a contractor						54,729.80	19,738.20	36,900.00	
	Amount paid for air travel						0.00	0.00	0.00	
	Amount paid for room and board						178.08	0.00	0.00	
	All other amounts paid						452.82	129.60	432.45	
	Total amount paid	0.00	0.00	0.00	0.00	0.00	55,360.70	19,867.80	37,332.45	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100019328	Hours worked as a contractor					154	1,903	1,909	900	154
	Amount paid as a contractor					7,878.00	97,133.75	93,330.00	44,400.00	7,675.00
	Amount paid for air travel									
	Amount paid for room and board						371.06	760.49	1,224.27	
	All other amounts paid						1,588.57	4,557.87	934.82	150
	Total amount paid	0.00	0.00	0.00	0.00	7,878.00	99,093.38	98,648.36	46,559.09	7,825.00
	Number of round trip flights to/from Syracuse									
Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
100025803	Hours worked as a contractor					1,728.50			150	244
	Amount paid as a contractor			65,113.17	81,141.81	76,662.50			7,500.00	12,200.00
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid					3,601.41			105.00	225.00
	Total amount paid	0.00	0.00	65,113.17	81,141.81	80,263.91	0.00	0.00	7,605.00	12,425.00
	Number of round trip flights to/from Syracuse									

DAG-2 VERO Employees - NMPC Employee
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Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
[redacted]	100028397	Hours worked as a contractor				2,603	2,161	2,019	1,811	771	58.5
		Amount paid as a contractor		4,171.28	134,566.12	95,247.43	85,622.39	73,856.92	69,924.50	29,176.39	4,095.00
		Amount paid for air travel					1,088.00	15,545.00	11,714.10	4,805.50	207.90
		Amount paid for room and board					1,061.07	13,719.21	9,537.49	3,896.16	210.53
		All other amounts paid				39,540.53	40,562.37	13,536.96	10,476.74	3,988.97	118.25
		Total amount paid		4,171.28	134,566.12	134,787.96	118,880.62	116,658.09	101,652.83	41,867.02	4,631.68
		Number of round trip flights to/from Syracuse					2	38	21	10	0
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100032743	Hours worked as a contractor							117		
		Amount paid as a contractor							5,162.50		
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid							1424.19		
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	6,586.69	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100033823	Hours worked as a contractor				632	1949.5	2,010	1,937	336	
		Amount paid as a contractor				24,628.50	76,030.50	81,724.50	78,692.25	13,104.00	
		Amount paid for air travel									
		Amount paid for room and board						1,017.00			
		All other amounts paid				7,660.13	18,850.35	19,568.51	17,863.21	170.5	
		Total amount paid	0.00	0.00	0.00	32,288.63	94,880.85	102,310.01	96,555.46	13,274.50	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
	100034018	Hours worked as a contractor						411	160		
		Amount paid as a contractor						17,398.89	6,596.83		
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid							3349.77		
		Total amount paid	0.00	0.00	0.00	0.00	0.00	17,398.89	9,946.60	0.00	0.00
		Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

[redacted]

Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100020074	Hours worked as a contractor					1807.5	894	755		
	Amount paid as a contractor					53,688.00	31,272.50	26,473.30		
	Amount paid for air travel									
	Amount paid for room and board						87.59	632.73		
	All other amounts paid					1,096.78	270.53	807.46		
	Total amount paid	0.00	0.00	0.00	0.00	54,784.78	31,630.62	27,913.49	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100031111	Hours worked as a contractor									
	Amount paid as a contractor	10,810.30								
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	10,810.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100028406	Hours worked as a contractor									
	Amount paid as a contractor	2,145.68	2,574.81							
	Amount paid for air travel									
	Amount paid for room and board									
	All other amounts paid									
	Total amount paid	2,145.68	2,574.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Number of round trip flights to/from Syracuse									
Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
100024543	Hours worked as a contractor							216	744	240
	Amount paid as a contractor							8,424.00	29,016.00	9,360.00
	Amount paid for air travel									
	Amount paid for room and board								5010.62	1558.24
	All other amounts paid								6538.29	1814.37
	Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	8,424.00	40,564.91	12,732.61
	Number of round trip flights to/from Syracuse									

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid
Annual Contract Expenses for former Employees Who Accepted a VERO

	Employee ID	Expenses	2002	2003	2004	2005	2006	2007	2008	2009	2010
[redacted]	**Employee ID**	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100028922	Hours worked as a contractor								988	256
		Amount paid as a contractor								38,678.25	9,984.00
		Amount paid for air travel									
		Amount paid for room and board								3287.09	
		All other amounts paid								6083.35	11.56
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48,048.69	9,995.56
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100026871	Hours worked as a contractor									
		Amount paid as a contractor	11,821.73	7,559.50							
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid									
		Total amount paid	11,821.73	7,559.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100033046	Hours worked as a contractor									
		Amount paid as a contractor		8,236.50							
		Amount paid for air travel									
		Amount paid for room and board									
		All other amounts paid									
		Total amount paid	0.00	8,236.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Number of round trip flights to/from Syracuse									
	Employee ID	**Expenses**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
	100020903	Hours worked as a contractor								185	39
		Amount paid as a contractor								7,254.00	1,501.50
		Amount paid for air travel									
		Amount paid for room and board								349	559.35
		All other amounts paid								388.34	200.9
		Total amount paid	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7,991.34	2,261.75
		Number of round trip flights to/from Syracuse									

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. DAG-2 SUPP
NMPC Req. No. NM 179 DPS 109

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO:

Request:

Follow-up to I/R #NM-28 (RAV-14).
In a format similar to the response to I/R #NM-28 (RAV-14), please provide the following information for each VERO employee that was a former NMPC employee; whether that employee either remained a NMPC employee; or whether, at some point, was transferred into the National Grid USA Service Co.

A. VERO employee's name;

B. The date of employee's retirement and salary at time of retirement;

C. Provide the costs of the employee being VERO'ed by type of cost.

D. Has the Company ever incurred costs associated with the same employee subsequent to the employee retiring? If yes, from the date of retirement up to the present time, please provide, in an Excel spreadsheet, the following information by calendar year:

1. Number of hours the VERO employee worked for the Company as a contracted employee;
2. Incurred costs for VERO employee's contractor services;
3. Incurred costs for VERO employee's travel expenses;
4. Incurred costs for VERO employee's lodging expenses;
5. Any other incurred costs for VERO employee;
6. Total costs incurred for VERO employee.

E. Indicate whether the above costs were charged to capital or expense, along with the reason for such accounting.

F. Indicate the date the VERO employee first performed contractor services for the Company.

G. Indicate if VERO employee is still a contracted employee; if not, indicate the last date that the employee performed contractor services for the Company.

Response:

The Company would like to supplement its response to this question. Please see Supplement 2 Attachment 1 for additional employees who accepted a VERO from NMPC from 2002 through 2010.

Request A is subject to a Protective Order.

Please see Supplement 2 Attachment 1 for responses to requests B, C, E, F and G.

D. The Company has not incurred any costs associated with any of the employees in Supplement 2 Attachment 1 after the employee retired.

Name of Respondent:	Date of Reply:
Ed Considine	4/22/10

DAG-2 VERO Employees - NMPC Employee
Docket Number 10-E-0050
Niagara Mohawk Power Corporation
Attachment 1 Supplement 2

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

VERO Employees

Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	01/01/2009	$63,398.40	79,248	0				
	07/01/2008	$63,398.40	116,551	0				
	07/01/2008	$63,398.40	77,380	0				
	07/01/2008	$55,463.20	79,317	0				
	01/01/2009	$66,398.40	108,399	0				
	01/01/2009	$63,398.40	133,176	0				
	01/01/2009	$51,126.40	143,594	0				
	01/01/2009	$51,126.40	84,305	0				
	07/01/2008	$30,272.52	128,492	0				
	01/01/2009	$66,476.80	187,901	0				
	07/01/2008	$63,398.40	88,907	0				
	07/01/2008	$63,398.40	90,618	0				
	01/01/2009	$63,398.40	177,992	0				
	07/01/2008	$55,463.20	137,314	0				
	07/01/2008	$20,925.60	130,603	0				
	08/01/2008	$63,398.40	132,895	0				
	01/01/2009	$63,398.40	75,359	0				
	07/01/2008	$9,422.76	95,101	0				
	01/01/2009	$51,126.40	104,457	0				
	01/01/2009	$51,126.40	67,378	0				
	01/01/2009	$63,398.40	72,379	0				
	07/01/2008	$63,398.40	110,263	0				
	08/01/2008	$63,398.40	186,333	0				
	01/01/2009	$51,126.40	28,546	0				
	01/01/2009	$51,126.40	65,469	0				
	01/01/2009	$60,746.40	117,688	0				
	01/01/2009	$63,398.40	109,307	0				
	07/01/2008	$55,463.20	120,964	0				
	07/01/2008	$63,398.40	165,384	0				
	01/01/2009	$63,398.40	125,762	0				
	01/01/2009	$51,126.40	44,474	0				
	01/01/2009	$51,126.40	33,444	0				

Niagara Mohawk Power Corporation (Electric) d/b/a National Grid

VERO Employees

Employee ID	Request B: Retirement Date	Request B: Last Wage	Request C: VERO Cost - Pension *	Request C: VERO Cost - Medical	Request F: First Date as Contractor	Request G: Last Date as Contractor	Request E: Contractor Costs Accounting	Request E: Reason for Accounting
[redacted]	08/01/2008	$51,126.40	109,329	0				
	01/01/2009	$63,398.40	98,215	0				
	01/01/2009	$51,126.40	128,420	0				
	01/01/2009	$55,463.20	57,141	0				
	01/01/2009	$63,398.40	182,793	0				
	07/01/2008	$63,398.40	128,883	0				
	07/01/2008	$55,463.20	79,152	0				
	01/01/2009	$63,398.40	181,595	0				
	01/01/2009	$51,126.40	56,738	0				
	01/01/2009	$63,398.40	91,551	0				

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. DAG-3
NMPC Req. No. NM 180 DPS 110

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirements Panel

Request:

The Company lists various vendors and cost estimates on page 216 of Exhibit __ (RRP-10) to support its rate year estimate for incremental rate case expenses. For each vendor listed on workpaper page 216, provide the following:

1. A copy of the contract and purchase order the Company has with the vendor that supports and identifies the work being performed.

2. A copy of all historic test year invoices with supporting documentation for total historic test year costs incurred and charged to Niagara Mohawk (company #36) either directly or indirectly. The supporting documentation should include the actual accounting applied so that verification of costs incurred can be reconciled with the historic test year workpapers provided in Exhibit __ (RRP-10).

Response:

1. Attached are the contracts and purchase orders the Company has with vendors identified on page 216 of Exhibit_(RRP-10). Per discussion with Denise Gerbsch, the Company did not provide documentation for newspapers or advertisements as these items were invoiced.
Foster and Associates (Attachment 1)
Analysis Group (Attachment 2)
Black and Veach (Attachment 3)
Hiscock & Barclay (Attachment 4)
Cullen & Dykeman (Attachment 5)
Alston & Bird (Attachment 6)
Towers Perrin (Attachment 7)
WarRoom (Attachments 8 and 9)

Roger Morin (Attachment 10)

2. There were no incremental costs during the historic test year.

Name of Respondent:
James Molloy

Date of Reply:
March 19, 2010

Form 103

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. RAV-48
NMPC Req. No. NM 185 DPS 115

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirements Panel & Infrastructure and Operations Panels

Request:

A. On page 84 of the Revenue Requirement Panel's pre-filed direct testimony, the "Transmission Hydro-One Transformer Project" is shown to have a 12/31/10 forecasted balance of $4.1 million.

Please provide a brief description of the project, why it is needed and what purpose it will serve. Include the project's cost benefit summary / analysis.
Please provide a breakdown of the costs that make up the project's $4.1 million estimate.
Please provide documentary support for the 12/31/10 in-service date.

B. On page 84 of the Revenue Requirement Panel's pre-filed direct testimony, the proposed treatment for the $4.1 million of Transmission Hydro-One Transformer Project costs is to amortize the costs over a 36 month period.

Fully explain the basis for the 36 month amortization period?
What is the useful life of the project? How does this useful life period tie into the project's cost benefit analysis?
At the end of the 36 month amortization period, what are the Company's plans for this asset? Sell it? Retire it? Continue using it? Explain in full.

C. Footnote 5 on page 84 of the Revenue Requirement Panel's pre-filed direct testimony states that the Company is requesting authority to capitalize costs of O&M associated with the work the Company is performing for Hydro-One and requests to defer and amortize these costs over three years. Footnote 5 also states that the costs are included in the testimony of the Infrastructure and Operations Panel.

Please indicate where in the Infrastructure and Operations Panel's 266 pages of testimony, these costs are discussed.
How much O&M, by cost component, is the Company requesting be capitalized? Over what period of time will these costs be incurred?
Is the O&M amount in C.2 above included in the $4.1 million estimate? If not, where in the Company's filing are these O&M costs reflected?

Form 103

Fully explain the basis for the Company's request to defer these O&M costs? To be eligible for deferral, the Commission has a materiality threshold which the Company has previously addressed and acknowledged in numerous responses to Staff information requests and proceedings before the Commission. Do these O&M costs meet the Commission's materiality threshold in order to be eligible for deferral? If so, explain how and provide the impact of such O&M costs on net operating income after income taxes.

Response:

A.1. The full description of the Hydro-One project - why it is needed, what purpose it will serve - is provided on pages 166-169 of the Infrastructure and Operations Panel ("IOP") Testimony. The cost benefit analysis for the replacement of the BP76 Transformer was based on the economic analysis performed by New York ISO, which calculates the day-ahead congestion shortfall resulting from the concurrent outages of the BP76 Transformer and 345kV outages on New York Power Authority system. The New York ISO economic analysis is provided in Attachment 1 (RAV-48 Attachment 1_NYISO Hydro One Economic Analysis). As indicated on page 168 of the IOP Testimony, the cost benefit analysis indicates there is an economic justification for replacement of the transformer.

A.2. As indicated in the IOP Testimony on pages 166-167, the replacement costs shown are an estimate of $9 million, based on information from Hydro-One at the time of the filing. A specific breakdown of the replacement costs is not yet available. Hydro One is in process of tendering bids for the project and determining the detailed project cost estimate and schedule. Pursuant to the terms of the Interconnection Facilities Agreement described on page 167 of the IOP Testimony, National Grid's cash outlay will be 50% of Hydro One's total cost to procure and install the new regulating transformer. The estimated National Grid cost for this project reflects an estimated September 2010 $4.5 million cash outlay to Hydro, whereas the $4.1 million in question reflects the unamortized deferred debit balance associated with this payment as of December 31, 2010 assuming the proposed 36 month amortization period. The exact timing and cash outlay amount will be based on Hydro One's detailed project cost estimate and the commercial arrangement with National Grid, which are in development and expected to be finalized later in 2010.

A.3. Documented support for the in-service date for the transformer will be based on the bids received later in 2010, along with Hydro One's detailed project schedule that is still in development. The current estimate for the in-service date is end of 2012. As noted on page 72 of the Revenue Requirements Panel Testimony, the Company will adjust the in service date if necessary at the time the Company submits Corrections and Updates in this proceeding.

B.1. National Grid proposes to spread the expense payment for replacement of the Hydro-One transformer over several years to lessen the impact on customers. Given that National Grid has proposed a three-year rate plan, a 36 month amortization period from the date of payment is a reasonable time period in this instance for rate stability.

B.2. We estimate the useful life of the project to be approximately 45 years based on similar assets owned by National Grid. The economic analysis by the NYISO was performed for a five month period and analyzed the operational scenario where the BP76 Transformer outage is combined with major transmission outages in the same region of New York. This operational scenario resulted in congestion costs to customers that would justify the replacement of the BP76 Transformer. We can expect congestion savings to take place over the useful life of the facility based on transmission outages required on the New York system.

B.3. The facility in question is owned by Hydro One. The replacement regulating transformer will continue to be located at Beck substation in Ontario, Canada and owned by Hydro One. Ownership and responsibility for normal maintenance of the associated with the BP76 regulating transformer rests with Hydro One, consistent with the terms of the Interconnection Facilities Agreement.

C.1. This is indicated in response A.1. above.

C.2. National Grid is requesting to capitalize the total unamortized deferred debit balance associated with the total amount expended for the expense payment to Hydro One, estimated at $4.5 million at the time of the rate plan proposal (reflecting 50% of the total transformer replacement costs). The Company is seeking to recover this cost over a 36 month amortization period.

C.3. This is explained in responses A.2. and C.2. above.

C.4. National Grid has asked for deferred recovery of these costs for rate stability purposes as explained in response B.1. above. National Grid believes these O&M costs would be eligible for deferral because (i) the Company is not expected to be over-earning in 2010; (ii) the estimated payment exceeds the $2 million materiality threshold per the merger rate plan; and (iii) these costs were not anticipated at the time of the Merger Rate Plan and thus are incremental to the original 10-year forecasts underlying the rates agreed to in the Merger Joint Proposal. Based on 12 months ended September 30, 2009, materiality thresholds of 3% and 5% of net income would be $3.2 million and $5.4 million. Because the Company projects 2010 net income to be lower than 2009, it is expected that the $4.5 million projected payment will meet the materiality threshold.

<u>Name of Respondent:</u> Bill Malee/James Molloy	<u>Date of Reply:</u> 03/15/10

Western_NY_Export DCR Allocation for BP76/PA301(PA302) for Spring 2009

Date	Daily Total $
3/24/2009	($468,427.23)
3/25/2009	($293,923.83)
3/26/2009	($175,258.32)
3/27/2009	($216,930.25)
3/28/2009	($199,520.87)
3/29/2009	($178,630.26)
3/30/2009	($188,900.28)
3/31/2009	($193,971.61)
4/1/2009	($474,008.92)
4/2/2009	($533,498.10)
4/3/2009	($215,419.56)
4/4/2009	($552,711.65)
4/5/2009	($362,293.98)
4/6/2009	($60,310.75)
4/7/2009	($333,632.37)
4/8/2009	($500,037.77)
4/9/2009	($442,079.70)
4/10/2009	($413,660.82)
4/11/2009	($276,103.75)
4/12/2009	($145,193.94)
4/13/2009	($438,718.72)
4/14/2009	($424,154.52)
4/15/2009	($381,563.55)
4/16/2009	($226,846.86)
4/17/2009	($141,310.15)
Totals	($7,837,107.76)
Outage-day Stdev	$141,790.95
Outage-day Max	($60,310.75)
Outage-day Min	($552,711.65)

Cost Basis	Assumed Daily DCR $	20 week Fall 2010 cost estimate $	21 day Fall 2009 cost estimate $
Spring 2009	($313,000)	($43,820,000)	($6,573,000)
Fall 2008	($555,000)	($77,700,000)	($11,655,000)

Date of Request: March 18, 2010
Due Date: March 29, 2010

Request No. RAV-48 (Supplement)
NMPC Req. No. NM 185 DPS 115

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirements Panel & Infrastructure and Operations Panel

Request:

A. On page 84 of the Revenue Requirement Panel's pre-filed direct testimony, the "Transmission Hydro-One Transformer Project" is shown to have a 12/31/10 forecasted balance of $4.1 million.

Please provide a brief description of the project, why it is needed and what purpose it will serve. Include the project's cost benefit summary / analysis.
Please provide a breakdown of the costs that make up the project's $4.1 million estimate.
Please provide documentary support for the 12/31/10 in-service date.

B. On page 84 of the Revenue Requirement Panel's pre-filed direct testimony, the proposed treatment for the $4.1 million of Transmission Hydro-One Transformer Project costs is to amortize the costs over a 36 month period.

Fully explain the basis for the 36 month amortization period?
What is the useful life of the project? How does this useful life period tie into the project's cost benefit analysis?
At the end of the 36 month amortization period, what are the Company's plans for this asset? Sell it? Retire it? Continue using it? Explain in full.

C. Footnote 5 on page 84 of the Revenue Requirement Panel's pre-filed direct testimony states that the Company is requesting authority to capitalize costs of O&M associated with the work the Company is performing for Hydro-One and requests to defer and amortize these costs over three years. Footnote 5 also states that the costs are included in the testimony of the Infrastructure and Operations Panel.

Please indicate where in the Infrastructure and Operations Panel's 266 pages of testimony, these costs are discussed.
How much O&M, by cost component, is the Company requesting be capitalized? Over what period of time will these costs be incurred?
Is the O&M amount in C.2 above included in the $4.1 million estimate? If not, where in the Company's filing are these O&M costs reflected?

Form 103

Fully explain the basis for the Company's request to defer these O&M costs? To be eligible for deferral, the Commission has a materiality threshold which the Company has previously addressed and acknowledged in numerous responses to Staff information requests and proceedings before the Commission. Do these O&M costs meet the Commission's materiality threshold in order to be eligible for deferral? If so, explain how and provide the impact of such O&M costs on net operating income after income taxes.

Response:

Upon further discussion with Staff, the Company seeks to clarify the following regarding Footnote 5.

The Company acknowledges that Footnote 5 could have been more descriptive. The Company is requesting authority to capitalize the expense payment of its share of the work for the Hydro One project (i.e., replacement of the regulating transformer). As described in the respective responses to B.3. and A.2. of RAV-48 submitted on March 16, 2010, Hydro One owns and is responsible for maintenance of the BP76 regulating transformer and National Grid will be responsible to pay 50% of Hydro One's total cost to procure and install the new regulating transformer, in accordance with the Interconnection Facilities Agreement described on page 167 of the Infrastructure and Operations Panel Testimony.

Name of Respondent:	Date of Reply:
Bill Malee	03/25/10

Date of Request: March 5, 2010
Due Date: March 15, 2010

Request No. RAV-49
NMPC Req. No. NM 186 DPS 116

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirements Panel

Request:

On pages 87-88 of the Revenue Requirement Panel's pre-filed direct testimony, it is stated that for fiscal year 2009, the Company changed its method of accounting for routine repair maintenance costs for federal income tax purposes, resulting in a tax benefit of approximately $200 million. Regarding this change in accounting, please provide the following information:

A. Please provide the back-up to this approximate $200 million tax benefit.

B. Fully explain if this accounting change resulted in any tax refund to the Company.

C. Please provide both the electric and gas tax benefits associated with this accounting change.

D. Indicate whether the Company agrees that it should be recording a deferred credit for the electric cash flow enhancement related to this accounting change under Clause 1.2.4.2 of the MJP. If not, explain in full.

E. Due to the timing of this accounting change, please indicate the Company's position as to which gas settlement agreement terms determine the proper ratemaking for this accounting change, those from the 6/12/00 gas settlement agreement in Case 99-G-0336 or those from the 2/13/09 gas settlement agreement in Case 08-G-0609. Briefly explain the Company's rationale for its position.

F. Depending on your answer to Part D. above:
Indicate whether the Company agrees that it should be recording a deferred credit for the gas cash flow enhancement related to this accounting change under Clause V.B.6 of the 6/12/00 gas settlement agreement in Case 99-G-0336 . If not, explain in full.

Form 103

Indicate whether the Company agrees that it should be recording a deferred credit for the gas cash flow enhancement related to this accounting change under Clause 4.2.1 of the 2/13/09 gas settlement agreement in Case 08-G-0609. If not, explain in full.

G. Provide separate calculations of the electric and gas cash flow benefits the Company has realized / will realize as a result of this accounting change from the date first realized up through 12/31/10. Include supporting workpapers and explain any assumptions.

H. On page 88, the Panel states that the Company is providing the full benefit of the tax credit in rate year rate base and requests authorization to defer for future recovery from ratepayers the amount of any future adjustments or disallowances with carrying charges at the weighted average cost of capital approved in this proceeding. If in response to Parts D. and F. the Company states that it does not agree that ratepayers are entitled to deferred credits for the cash flow enhancement related to this accounting change pre-rate year, fully explain the reasonableness and equity of this requested rate year deferral of the potential cash flow loss (which only involves any disallowed portion of the $200 million). In other words, why does the Company believe is it fair for stockholders to retain 100% of the pre-rate year cash flow enhancement on the $200 million tax benefit, while making ratepayers pay 100% of the rate year cash flow loss on the portion of the $200 million the IRS possibly disallows?

I. Fully explain how the Company derived the forecasted repair allowance related tax benefits for the periods post-FYE 3/09. Explain how and why these post-FYE 3/09 tax benefits differ from the amount claimed on the FYE 3/09 tax return. Include supporting workpapers for the forecasted amounts.

Response:

A. The $200 million refers only to the electric segment. Please see Exhibit __(RRP-10) Workpapers to Exhibit ___(RRP-6), Schedule 3, Workpaper 1, Sheet 1 (Page 272 of Book19) Fiscal 2009 true up line for the $208,438,765 estimate. This amount is made up five numbers pulled from page 14 of that workpaper that compares the Fiscal 2009 accrual to the Fiscal 2009 return. Below is a description of each of these.

Total Federal change	228,378,861
Less FIT on State change	(19,120,002)
Plus COR Federal change	14,712
Less FIT on State change	(1,306)
Less COR DIT change	(833,500)
Total	208,438,765

B. Although the Revenue Requirements Panel's testimony indicates that the Company changed its method of accounting, this testimony requires clarification. In 2009, the Company for the first time took a tax deduction for routine repairs and maintenance costs that had been capitalized and depreciated. The Company's actions did not represent a change in accounting, but rather reflected a change in its interpretation of its rights under the Internal Revenue Code. As discussed in the testimony, the Company's interpretation is subject to audit. The Company received a refund as a result of overpayments during FYE 3/09.

C. As stated in response to B, the Company has not changed its accounting, it has taken an incremental tax deduction. Please see part A for the Electric segment and Attachment 1, page 2 to this response for a calculation of the Gas segment.

D. The Company does not agree that it should be recording a deferred credit for the electric cash flow enhancement related to this incremental tax deduction under Clause 1.2.4.2 of the MJP. Clause 1.2.4.2.1 addresses externally imposed tax and accounting changes and Clause 1.2.4.2.2 addresses internally imposed changes in Accounting Policies. As discussed in response to B, there has been no change in tax law or accounting policy, therefore this item does not fall under either clause of the MJP. The Company is simply taking a tax deduction for the first time.

E. As stated in response to B, the Company has not changed its accounting, it has taken an incremental tax deduction. The Company believes that the transaction would be covered under the terms of gas settlement agreement in Case 08-G-0609 as the effects of the transaction only affect post rate plan costs.

F. The Company does not agree that it should be recording a deferred credit for the gas cash flow enhancement related to this incremental tax deduction under Clause 4.2.1. Clause 4.2.1 addresses regulatory, legislative and accounting changes. As stated in part D, because there has been no change in tax law or accounting this item does not fall under this clause of the settlement agreement in Case 08-G-0609. The Company is simply taking a tax deduction for the first time.

G. As stated in response to B, the Company has not changed it accounting, it has taken an incremental tax deduction. Please see Attachment 2 to this response.

H. The Company is not proposing to charge customers for any period before the customers received the benefit. Any interest charges assessed for disallowance for the period from the initial deduction until the effective date will be shareholders responsibility, so there is a matching between the benefits and costs.

I. Please see Workpaper 1 to Schedule 3 to Exhibit ___ (RRP-6) (Page 271 to 285 of Book 19). Post FYE 3/09 repair deductions are assumed to be 50% of plant additions. FYE 3/09 repair deduction included a catch-up from FYE 03/0x to FYE 3/09.

<u>Name of Respondent:</u>
Tax Department
James Molloy

<u>Date of Reply:</u>
April 19, 2010

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Fiscal 2009 Accrual to Return Adjustment - ELECTRIC

	Fiscal 09 Accrual	Fiscal 09 Return	Change	Balance Sheet Tax Effect	
Plant Related Changes:					
Tax Depreciation - Federal	(249,547,192)	(192,681,468)	56,865,724		
Tax Depreciation - State	(203,291,841)	(185,559,608)	17,732,233		
Repair Allowance - Federal	0	(708,949,368)	(708,949,368)		
Repair Allowance - State	0	(786,721,424)	(786,721,424)		
CIAC - Electric Only	17,894,200	11,792,826	(6,101,374)		
Asset Retirements	0	0	0		
Salvage - 100% Electric	0	5,332,601	5,332,601		
Capitalized Interest - Electric Only	1,446,491	1,787,876	341,385		
Federal @ 35%			(652,511,032)	(228,378,861)	
State @ 7.1%			(769,416,579)	(54,628,577)	
FIT on SIT				19,120,002	
Cost of Removal - Electric Only	(34,741,673)	(34,794,215)	(52,542)	(14,712)	Federal @ 80% x 35%
				(3,730)	State @ 7.1%
				1,306	FIT on SIT
Reversal of COR DIT - Electric Only	5,973,500	6,807,000	833,500	833,500	Federal Only
Total Electric Adjustments				(208,438,765)	

Note this is the same as Sheet 14 of Workpaper 1 to Schedule 3 of Exhibit ___RRP-6

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Fiscal 2009 Accrual to Return Adjustment - GAS

	Fiscal 09 Accrual	Fiscal 09 Return	Change	Balance Sheet Tax Effect	
Plant Related Changes:					
Tax Depreciation - Federal	(80,585,355)	(65,770,885)	14,814,470		
Tax Depreciation - State	(65,648,285)	(51,562,540)	14,085,745		
Repair Allowance - Federal	0	(143,046,216)	(143,046,216)		
Repair Allowance - State	0	(145,916,444)	(145,916,444)		
CIAC - Gas Only	5,105,800	4,285,825	(819,975)		
Asset Retirements	0	0	0		
Salvage - 100% Gas	0	(13,663)	(13,663)		
Capitalized Interest - Gas Only	162,509	200,863	38,354		
Federal @ 35%			(129,027,030)	(45,159,461)	
State @ 7.1%			(132,625,983)	(9,416,445)	
FIT on SIT				3,295,756	
Cost of Removal - Gas Only	(4,167,454)	(4,114,912)	52,542	14,712	Federal @ 80% x 35%
				3,730	State @ 7.1%
				(1,306)	FIT on SIT
Reversal of COR DIT - Gas Only	707,500	897,000	189,500	189,500	Federal Only
Total Gas Adjustments				(41,660,799)	

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Repair Tax Deduction Cash Flow Benefits

	Total	Electric	Gas
Fiscal 2009 (Attachment 1)	250,099,564	208,438,765	41,660,799
Fiscal 2010 (Page 2)	54,500,567	45,606,276	8,894,291
Fiscal 2011 through December (Page 2)	40,099,213	33,538,209	6,561,004
Total	344,699,344	287,583,250	57,116,094

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Repair Tax Deduction Cash Flow Benefits

	Total	Electric	Gas
Fiscal 2010			
Total Plant Additions	506,000,000	419,980,000	86,020,000
Repair Additions	202,400,000	167,992,000	34,408,000
Pre Repair Depreciation			
Current Year	6,476,643	7,226,337	1,720,400
Prior Years	55,877,682	45,641,907	10,235,774
Total Pre Repair Tax Depreciation	62,354,325	52,868,244	11,956,174
Post Repairs Expense			
Current Years	202,400,000	167,992,000	34,408,000
Prior Years	-	-	-
Total Post Repair Tax Depreciation	202,400,000	167,992,000	34,408,000
Tax Calculation			
Total Change in Depreciation/Expense	(140,045,675)	(115,123,756)	(22,451,826)
Federal Tax	(49,015,986)	(40,293,315)	(7,858,139)
State Tax	(9,943,243)	(8,173,787)	(1,594,080)
Federal on State Tax	3,480,135	2,860,825	557,928
Net Tax Change Fiscal 2010	(55,479,094)	(45,606,276)	(8,894,291)
Fiscal 2011 through December (9 months)			
Total Plant Additions	366,299,076	304,028,233	62,270,843
Repair Additions	146,519,630	121,611,293	24,908,337
Pre Repair Depreciation			
Current Year	6,476,643	5,231,226	1,245,417
Prior Years	38,820,690	31,719,689	7,101,001
Total Pre Repair Tax Depreciation	45,297,333	36,950,916	8,346,417
Post Repair Depreciation			
Current Years	146,519,630	121,611,293	24,908,337
Prior Years	-	-	-
Total Post Repair Tax Depreciation	146,519,630	121,611,293	24,908,337
Tax Calculation			
Total Change in Depreciation	(101,222,297)	(84,660,378)	(16,561,920)
Federal Tax	(35,427,804)	(29,631,132)	(5,796,672)
State Tax	(7,186,783)	(6,010,887)	(1,175,896)
Federal on State Tax	2,515,374	2,103,810	411,564
Net Tax Change Fiscal 2011 through Dec	(40,099,213)	(33,538,209)	(6,561,004)
Repair Rate	40%		

Date of Request: May 3, 2010
Due Date: May 13, 2010

Request No. RAV-49 SUPP
NMPC Req. No. NM 186 DPS 116

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirements Panel

Request:

In reviewing the Co's response to IR RAV-49, Part B, I just noticed that the Co stated that it "received a refund as a result of overpayments **during FYE 3/09**" [emphasis added].....................I'd like to know the exact date(s) during FYE 3/09 when the refund was received. If the refund came in stages, please provide the amounts received on each date.

Response:

A. The timing needs to be clarified. The Company did not receive any refund in FYE 3/09 rather the refunds related to overpayments of our estimated FYE 3/09 taxes. As can be seen in Attachment A (Federal Intercompany tax payments trueup), NMPC received its portion of the refund of estimated taxes paid -- $266,937,221 – in April 2010. NMPC is part of a group filing a consolidated federal tax return under National Grid Holdings Inc. ("NGHI"). NGHI received the group's entire refund of estimated taxes in December 2009 and distributed it to the group members in accordance with the provisions of the tax sharing agreement.

Name of Respondent:
James Molloy

Date of Reply:
May 13,2 010

Form 103

TO:	Accounting Team	Metrotech	**DATE:**	4/28/10 10:30 AM	
FROM:	Charles Derosa	Metrotech	**FILE:**	see below	
SUBJECT:	Federal Intercompany tax payments trueup due for fiscal year ended 3/31/09				

The following cash intercompany tax payments will be processed by wire transfer on April 30, 2010. These payments are the true-up amounts due to/from each company with respect to its share of the consolidated federal corporate income tax liability for the fiscal year ended March 31, 2009.

Our intercompany tax allocation agreement requires a transfer of cash among the companies participating in the consolidated tax return.

The payments computed below are based upon the federal tax true-up calculations prepared for March 31, 2009. Please refer to the attached worksheet for amounts by company.

Business Unit	Company Name	Project	Work Order	UK Account Number	Activity 236200
70001	NGHI	X05122	9000037089	620001	583,585,356
70003	NGUS LLC	X05122	9000037089	620001	32,052
00001	NGUSA	X05122	9000037089	620001	25,300,000
00004	NANT ELECTRIC	X05122	9000037089	620001	(4,710,263)
00005	MASS ELECTRIC	X05122	9000037089	620001	(83,596,440)
00010	NEPCO	X05122	9000037089	620001	(56,644,556)
00020	NEET	X05122	9000037089	620001	(103,654)
00021	NGTSC	X05122	9000037089	620001	(18,398)
00041	GRANITE STATE	X05122	9000037089	620001	(4,060,078)
00048	NARR GAS	X05122	9000037089	620001	(7,045,621)
00049	NARR ELECTRIC	X05122	9000037089	620001	(40,647,097)
00070	WAYFINDER	X05122	9000037089	620001	(183,737)
00082	GA HOLDINGS	X05122	9000037089	620001	(15,369)
00085	NEES ENERGY	X05122	9000037089	620001	(4,886)
00086	EUA EI	X05122	9000037089	620001	(21,848)
00099	NGUSA SC	X05122	9000037089	620001	2,218,807
00035	NMHI	X05122	9000037089	620001	857,910
[redacted]					
00037	ONAI	X05122	9000037089	620001	(1,006)
NMPROP	NM Properties, Inc.	X05122	9000037089	620001	(24,748)
Co 60	KeySpan				(147,979,213)
	TOTAL				-

These payments should be charged/credited to the respective company's Accrued Federal Corporation Income Tax Account, Activity 236200.

Date of Request: May 13, 2010
Due Date: May 24, 2010

Request No. RAV-49 SUPP 2
NMPC Req. No. NM 186 DPS 116

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Revenue Requirements Panel

Request:

This response (RAV-49 SUPP) totally contradicts what the Company provided in Attachment 2 of its response to RAV-49. On Attachment 2, the Company provided cash flow benefits for this repair tax deduction of $250M in FY 2009. How could there be any cash flow benefit in FY 2009, given this supplemental response states that the refund was not received until December 2009? At a bare minimum, the original Attachment 2 needs to be explained as to what the Company meant by stating there were cash flow benefits in FY 2009, and Attachment 2 might also need to be modified for "real" cash flow benefits in FY 2009, FY 2010 and FY 2011 thru 12/10, depending on your explanation.

Response:
Attachment 2 of our RAV-49 response provided an estimate of the cash flow benefit associated with three separate tax years. There was no cash flow benefit that actually occurred during fiscal 2009. The confusion likely stems from the layout of the schedule that showed a cash flow benefit with respect to fiscal 2009. The Company did not "stat[e] there were cash flow benefits **in** FY 2009." (emphasis added).

During fiscal 2009, the Company paid estimated tax for fiscal 2009 activity per Treasury Regulations. To comply with estimate tax requirements both prior year taxable income and current year activity are considered. None of these estimated tax payments were effected by the repairs deduction because the repairs study was not completed when the Company's estimated tax payments were due. When the Company filed its fiscal 2009 federal tax return in December 2009 the impact of our repairs study was estimated and caused taxable income to be less than what was estimated when the installment tax payments were due. Therefore, the IRS returned the Company's estimated tax payments made with respect to fiscal 2009. The Company received a refund in December of 2009.

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Please also note that the fiscal 2009 numbers in Attachment 2 of our RAV-49 response are based on schedules prepared prior to the tax return being filed. The schedule included estimates.

Finally, please see the Attachment and the response to RAV 134 Part D for the impact on estimated tax payments.

Name of Respondent:
Aaron Russell/James Molloy

Date of Reply:
5/19/2010

RAV-49 SUPP 2
Attachment

Niagara Mohawk's Cash Flow Benefit of Repairs Project

				Electric	83%
				Gas	17%
Date	**Cash Flow Amount (E)**	**Cash Flow Amount (G)**	**Total**	**Cash Flow Benefit**	
12/15/2009	$ -	$ -	$ -		
12/22/2009	$ 221,557,893	$ 45,379,328	$ 266,937,221	$ 266,937,221	
03/15/2010	$ 14,525,000	$ 2,975,000	$ 17,500,000	17500000	
06/15/2010	$ 14,525,000	$ 2,975,000	$ 17,500,000	17500000	
09/15/2010	$ 14,525,000	$ 2,975,000	$ 17,500,000	17500000	
12/15/2010	$ 14,525,000	$ 2,975,000	$ 17,500,000	17500000	
03/15/2011	$ -	$ -	$ -		
06/15/2011	$ -	$ -	$ -		
09/15/2011	$ -	$ -	$ -		
12/15/2011	$ -	$ -	$ -		

Date of Request: March 9, 2010
Due Date: March 19, 2010

Request No. DKS-6
NMPC Req. No. NM 196 DPS 126

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: David Shahbazian

TO: Revenue Requirement Panel

Request:

1. In a format identical to the schedule presented in the Injuries and Damages workpapers #183-184 (Exhibit __ RRP-10), please provide the detailed information for each of the following historical years (electric amounts should reconcile to the electric amounts shown on workpaper #185):
10/01/2003 - 9/30/2004
10/01/2004 - 9/30/2005
10/01/2005 - 9/30/2006
10/01/2006 - 9/30/2007
10/01/2007 - 9/30/2008

2. In a format identical to the schedule presented in the Injuries and Damages workpaper #186 (Exhibit __ RRP-10), please provide the detailed information for each of the following historical years:
10/01/2003 - 9/30/2004
10/01/2004 - 9/30/2005
10/01/2005 - 9/30/2006
10/01/2006 - 9/30/2007
10/01/2007 - 9/30/2008

3. Injuries & Damages workpaper #185 shows a grand total electric claims expense amount of $3,760,357. Exhibit __ (RRP-2) Schedule 34, Sheet 5 of 7, shows total historic year electric claims expense of $4,005,827. Please explain the difference and provide detail supporting the difference of $245,470.

4. Exhibit RRP-2, schedule 34, sheet 7, shows the Insurance Premium Tax per book amount of $1.17 million as of September 30, 2009. Please provide all workpapers
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and supporting calculations that support the Insurance Premium Tax recorded, including the reclass entries as noted on workpaper #186.

5. Please identify any insurance carrier providing coverage to Company 36 that provides 'continuity credits' or any other type of credit / rebate to its clients for loyalty (successive annual renewals), or any other reason including reduced number of claims paid for a given period of time.

6. Exhibit __ (RRP-2), schedule 34, sheet 7, outlines the Company's Injuries & Damages Historic Year Ended September 30, 2009 as adjusted amount of $6,406,683 for Niagara Mohawk. Workpaper #186 shows the historic test year per book amount of $5,445,492. For each component listed on Exhibit __ (RRP-2) Schedule 34, Sheet 7, provide a detailed calculation showing the flow from the historic test year to the adjusted historic test, along with an explanation and supporting justification and documentation of what the adjustment to the historic test year is for.

7. Please provide the following for each insurance policy charged to the Company in support of the 'Adjusted Book Amounts' of $6,406,683 as shown on Exhibit __ (RRP-2), schedule 34, sheet 7.
   a) The Declaration page(s) for showing the term / dates of coverage.
   b) The total premium amount.
   c) The listing showing the Insured covered by each policy.
   d) The allocation methodology as it applies to each policy and breakdown among all affiliates / service companies covered by the policy.

8. With reference to the insurance coverage purchased on behalf of Company 36, please provide copies of all current insurance brokerage agreements that show the brokerage fee, and term of agreement as well as originating organization for each.

9. Exhibit RRP-2, schedule 34, sheet 7, and workpaper #185 from Exhibit __ (RRP_10) outlines the Company's Historical Claim and presents historical averages for 3, 4, 5, and 6 year averages. Please provide the reasoning behind the Company's ultimate selection of a 3 year average (versus a 4 or 5 year average, etc) in its presentation of claim data and for use in for forecasting rate year claims expense.

Response:

1. Attachment 1 provides information for the summary of Claims paid in the format similar to workpaper page 185 as per conversation with the David Shahbazian. Attachments 2 to 13 provides a list of all claims paid for the periods requested. The amounts do not reconcile to the electric amounts shown on work paper #185. This is because payment information queries are run for cases closed in the period only, as of a specific point in time. We ran the queries for the historical test period data, at 11/16/09, the information gathered was for total payments for the various time periods based on close date. The new reports provide data at 3/18/10. Differences arise from the fact that claims can be reopened after being closed. When this happens the claim retains the original close date in the system.

2. Attachment 14 presents the a schedule similar to workpaper 183 and 184(Exhibit ___ RRP -10) for the 12 month periods ended 9/30/05 to 9/30/08. The identical page 186 was not available for these years. Per conversation with PSC requestor David Shahbazian I am providing similar actual recorded information for those periods by the same insurance premium categories. 9/30/04 data was not available due to the transition to a new accounting system in that year.
3. The $3,760,357 on workpaper 185 represents total claims paid in the period as detailed in response to question 1 above. The $4,005,827 represents the total booked expense for claims that contains various accounting accruals. The Company is forecasting claims expenses on a three year average of actual claims paid during the periods. This is the same methodology applied in the Company's Gas filing in Case 08-G-0609.
4. Please see Attachment 15 for the supporting workpaper.
5.

   There are three insurance carriers that provide coverage to Company 36 that may provide continuity credits based on successive annual renewals or a dividend based on claims paid out. These continuity credits or dividends are not guaranteed or contractual and are subject to the insurance carrier's determination to declare and pay them.

   The insurance carriers are Global Aerospace Underwriting Managers Ltd., Associated Electric & Gas Insurance Services (AEGIS) and Energy Insurance Mutual (EIM)
6. The $6,406,683 represents both the Electric and Gas portion of the adjusted Book amounts. The Electric allocated amount is $4,811,899 as referenced on Schedule 34. This amount is also referenced in the table at the top of workpaper 186 and is compared with the actual Electric booked amounts in the column to the left. The adjustments to the historical year as presented on workpapers 186 and 187 represent the annualization of the most current premiums of $75,995 and an adjustment to normalize for a prior period charge related to premium tax payments of ($709,587).
7. a) See Attachment 16 for copies of insurance policy Declaration pages.
   b, c, d) See Attachment 17 for a table listing insurance policies, premium amounts, percentage and amount allocated to Niagara Mohawk and Billing Pool reference; see Attachment 18 for copies of insurance premium invoices and payment requests. Attachment 19 provides copies of insurance premium tax payments.
8. See the attachment 20 for the McGriff, Seibels and Williams, Inc.:
   BSA below is for the period 12/01/09 to 12/01/10.
   The agreement with Marsh USA BSA is not finalized and will be provided when it is completed.

9. The Company selected the 3-year average for forecasting rate year claims expense because the period is more representative of recent claims activity. At present, there are seven cases on the books with potential for excessive settlements or verdicts.

Also recent trends in increased asbestos litigation and Verizon lawsuits are some of the reasons for increased claims in recent years.
The Company did not select the 5-year average ($4,816,882), 6-year average ($4,816,882) or average of averages ($5,167,094) because each is less representative of current claims activity. It is believed that each scenario understates recent activity.

Name of Respondent:
James Molloy/Pete Luvera

Date of Reply:
3/26/2010

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Insurance Premium Tax 10/1/08 - 9/30/09

Request No. DKS-6
NMPC Req. No. NM 196 DPS 126
Response to RFI No. 4

From Schedule 34, Sheet 7:

Category	Description	Niagara Mohawk
Ins Premium Tax	2009	173,455
	2009	149,141
	2008	854,925
		$ 1,177,520
Removal of 2008 Tax adjustment		(854,925)
Adjusted Ins Premium Tax		$ 322,595

Reconcile Insurance Premium Tax to Workpapers
and Schedule 34, sheet 7

							Federal Excise Tax (FET)					NY Surplus Line Tax				Total Tax
						Allocation Code:	00380	00382	00380	00380	00382	Direct				
						PeopleSoft Activity:	AG0275	AG0278	AG0278	AG0278	AG0278	AG0275	AG0278	AG0278	AG0278	
						Payment Date:	Jan-09	Apr-09	May-09	Jul-09	Sep-09	Jan-09	Aug-09	Aug-09	Aug-09	10/1/08 - 9/30/09
							(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
BUSI UNIT	SEG	EXP TYPE	ORIG DEPT	CHG DEPT	ORIG BUSI UNT	STATE	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT
00036	DIST	400	12230	12230	00099	NY	$5,620.96	$44,771.01	$38.76	$9,550.47	$1,025.24	$103,251.62	$41,733.00	$39,276.00	$3,361.00	$248,628.06
00036	GAS	400	12230	12230	00099	NY	$1,308.99	$8,539.27	$9.03	$2,223.98	$195.55	$24,044.90	$7,960.00	$8,332.00	$783.00	$53,396.72
00036	TRAN	400	12230	12230	00099	NY	$769.99	$5,985.38	$5.31	$1,308.38	$137.06	$14,144.06	$5,579.00	$5,317.00	$460.00	$33,706.18
						TOTAL	$7,699.94	$59,295.66	$53.10	$13,082.83	$1,357.85	$141,440.58	$55,272.00	$52,925.00	$4,604.00	$335,730.96

(a) Tax Filed Jan-09:.	$14,519.70	FET for 12/1/08-09 D&O for legacy NG ($13,950.30 legacy KS; total tax $28,470.00).
(b) Tax Filed Apr-09:	$187,924.00	FET for 4/1/09-10 NGICL insurance.
(c) Tax Filed May-09:	$100.69	FET interest on year 2000-2007 filings.
(d) Tax Filed Jul-09	$24,812.86	FET interest on year 2000-2007 filings.
(e) Tax Filed Sep-09:	$4,309.39	Additional FET for 12/1/08-09 D&O.
(f) Tax Filed Jan-09:.	$141,440.58	NYS interest on year 2002-2006 filings.
(g) Tax Filed Aug-09:	$108,777.00	NYS surplus line tax for 4/1/09-10 Ex GL.
(h) Tax Filed Aug-09:	$101,209.00	NYS surplus line tax for 4/1/09-10 NGICL insurance.
(i) Tax Filed Aug-09:	$8,185.00	NYS surplus line tax for 4/1/09-10 Property Terrorism.

Reconcile to WP Final Exhibit

(b+c+d+e)	(g+h+i)
$59,295.66	
$53.10	$55,272.00
$13,082.83	$52,925.00
$1,357.85	$4,604.00
$73,789.44	$112,801.00

Reconcile to WP 3 Insurance

AG0278 (b+e+g+h+i)	AG0275 (a+f)
$59,295.66	
$1,357.85	
$55,272.00	
$52,925.00	$7,699.94
$4,604.00	$141,440.58
$173,454.51	$149,140.52

Exhibit (RRP-10)
Workpapers to Exhibit RRP-2
Schedule 34
Workpaper 2
Sheet 1 of 1

Niagara Mohawk Power Corporation
Historical Claim Data
Electric Distribution and Transmission only

Valued as of 11/16/09

Request No. DKS-6
NMPC Req. No. NM 196 DPS 126
Response to RFI No. 1 - Provide Detailed Info.
Variance explanation of Historical Claim Payments
(11/16/09 reports) to Detail Reports (3/18/10 reports)

Witness: Revenue Requirement Panel

Claim Payments

See Notes.

Period	General Liability Litigated	General Liability Non-Litigated	Automobile Liability Litigated	Automobile Liability Non-Litigated	Total Gen Liab	Total Auto Liab	Grand Total	Detail Reports at 3/18/10 Claim Pmts GL & Auto	Detail Reports at 3/18/10 Variance from 11/15/09 Rpts Over / (Under)
Distribution & Transmission:							(x)	(y)	(z) = (y) - (x)
10/01/03 - 09/30/04	46,689.77	1,183,142.66	1,080.96	200,486.94	1,229,832.43	201,567.90	1,431,400.33	1,403,792.24	(27,608.09)
10/01/04 - 09/30/05	163,366.57	1,257,423.25	4,620.92	290,450.62	1,420,789.82	295,071.54	1,715,861.36	1,763,978.38	48,117.02
10/01/05 - 09/30/06	1,216,872.92	1,270,876.23	1,664,661.79	195,973.60	2,487,749.15	1,860,635.39	4,348,384.54	4,319,030.21	(29,354.33)
10/01/06 - 09/30/07	5,967,910.91	2,007,200.27	153,583.14	475,965.61	7,975,111.18	629,548.75	8,604,659.93	8,941,964.12	337,304.19
10/01/07 - 09/30/08	2,584,804.58	1,802,614.78	937,054.86	330,673.45	4,387,419.36	1,267,728.31	5,655,147.67	5,995,334.59	340,186.92
10/01/08 - 09/30/09	285,320.20	1,447,542.13	1,631,378.03	396,116.54	1,732,862.33	2,027,494.57	3,760,356.90	3,683,790.66	(76,566.24)
3 Yr Avg - Electric	**2,946,011.90**	**1,752,452.39**	**907,338.68**	**400,918.53**	**4,698,464.29**	**1,308,257.21**	**6,006,721.50**	**6,207,029.79**	200,308.29
4 Yr Avg - Electric	**2,513,727.15**	**1,632,058.35**	**1,096,669.46**	**349,682.30**	**4,145,785.51**	**1,446,351.76**	**5,592,137.26**	**5,735,029.90**	142,892.64
5 Yr Avg - Electric	**2,043,655.04**	**1,557,131.33**	**878,259.75**	**337,835.96**	**3,600,786.37**	**1,216,095.71**	**4,816,882.08**	**4,940,819.59**	123,937.51
6 Yr Avg - Electric	**1,710,827.49**	**1,494,799.89**	**732,063.28**	**314,944.46**	**3,205,627.38**	**1,047,007.74**	**4,252,635.12**	**4,351,315.03**	98,679.91
Avg. of Averages - Electric	**2,303,555.39**	**1,609,110.49**	**903,582.79**	**350,845.31**	**3,912,665.89**	**1,254,428.11**	**5,167,093.99**	**5,308,548.58**	141,454.59

Rate Case base year 2009

Notes: Claim Payment values from the database are specific to a given point in time Therefore, the values run on 11/16/09 differ from those run on 3/18/10. This is because Claims Paid can only be run for claims with a Closed status. It is, however, possible for a claim to be re-opened, if warranted, for new charges of liability or if a lawsuit is filed.

Number of Claims

Period	General Liability Litigated	General Liability Non-Litigated	Automobile Liability Litigated	Automobile Liability Non-Litigated	Total Gen Liab	Total Auto Liab	Grand Total	Detail Reports at 3/18/10 Claim Pmts GL & Auto	Detail Reports at 3/18/10 Variance from 11/15/09 Rpts
Distribution & Transmission:							(x)	(y)	(z) = (y) - (x)
10/01/03 - 09/30/04	10	1,289	1	114	1,299	115	1,414	1,395	(19)
10/01/04 - 09/30/05	16	1,027	4	129	1,043	133	1,176	1,142	(34)
10/01/05 - 09/30/06	24	861	5	96	885	101	986	979	(7)
10/01/06 - 09/30/07	21	901	2	330	922	332	1,254	1,237	(17)
10/01/07 - 09/30/08	22	844	6	161	866	167	1,033	1,031	(2)
10/01/08 - 09/30/09	16	1,011	5	135	1,027	140	1,167	1,142	(25)
3 Yr Avg - Electric	**20**	**919**	**4**	**209**	**938**	**213**	**1,151**	**1,137**	(15)
4 Yr Avg - Electric	**21**	**904**	**5**	**181**	**925**	**185**	**1,110**	**1,097**	(13)
5 Yr Avg - Electric	**20**	**929**	**4**	**170**	**949**	**175**	**1,123**	**1,106**	(17)
6 Yr Avg - Electric	**18**	**989**	**4**	**161**	**1,007**	**165**	**1,172**	**1,154**	(17)
Avg. of Averages - Electric	**20**	**935**	**4**	**180**	**955**	**184**	**1,139**	**1,124**	(15)

Rate Case base year 2009

NMPC
Summary of Claims and Insurance Premiums
Charged in Expense type 400 to Company 36
By Electric and Gas

Fiscal Yr	(All)	**Injuries and Damages**
Period	**(All)**	**HTY ending Sept 30, 2005**
Regulatory Acct Des	(All)	
Regulatory Acct	(All)	
Business Unit	00036	
Jrnl Id	(All)	
Expense Type	400	
Chrg Dept L3	(All)	
Chrg Dept L2	(All)	

Sum of Posted Jrnl $				Segment					**Electric**			**Gas**		
Orig Business Unit	**Activity**	Chrg Dept L4	**Activity Descr**	DIST	GAS	TRAN	Grand Total	Costs associated with Insurance	Costs associated with Claims	Costs associated with All Other	Costs associated with Insurance	**Costs associated with Claims**	Costs associated with All Other	Total
00036	AG0235	LEGAL_SERVICES	General Legal Claims	2,425.95			2,425.95		2,425.95			-		2,425.95
	AG0485	CORPORATE_COMM	Provide Safety & Health Se	1,867.25			1,867.25			1,867.25			-	1,867.25
		INTEGRATED_HEALTH	Provide Safety & Health Se	16,551.03	1,825.50	1,421.99	19,798.52			17,973.02			1,825.50	19,798.52
		LEGAL_SERVICES	Provide Safety & Health Se	300.00			300.00			300.00			-	300.00
		SAFETY_SERVICES	Provide Safety & Health Se	32,939.99	4,429.86	2,605.78	39,975.63			35,545.77			4,429.86	39,975.63
	AG0271	INSURANCE	U.S. Insurance-Liability	1,254,318.62	574,066.61	358,058.82	2,186,444.05	1,612,377.44			574,066.61			2,186,444.05
	AG0276	INSURANCE	U.K. Insurance-Property	686,508.00	283,229.45	166,605.55	1,136,343.00	853,113.55			283,229.45			1,138,343.00
	AG0281	CUST_OPERATIONS	Claims-Liability - Excl. Auto	9,461.76			9,461.76		9,461.76			-		9,461.76
		IS_ELEC_DIST_GEN_RTB	Claims-Liability - Excl. Auto	2,181.26			2,181.26		2,181.26			-		2,181.26
		US_TREASURY	Claims-Liability - Excl. Auto	563.14	470.19		1,033.33		563.14			470.19		1,033.33
		CLAIMS	Claims-Liability - Excl. Auto	1,596,315.39	146,842.75	10,081.17	1,753,239.31		1,606,396.56			146,842.75		1,753,239.31
	AG0282	US_TREASURY	Claims-Liability - Auto Only	2,565.11			2,565.11		2,565.11			-		2,565.11
		CLAIMS	Claims-Liability - Auto Only	380,540.66	18,432.48		398,973.14		380,540.66			18,432.48		398,973.14
	AG0283	CLAIMS	Claims-Accrual (Reserve)	1,041,913.45	264,893.25	459,148.30	1,765,955.00		1,501,061.75			264,893.25		1,765,955.00
	AG0289	FLEET_MGMT	Claims Group-Dept Operati	(308.14)	(71.66)	(42.00)	(421.80)		(350.14)			(71.66)		(421.80)
		INSURANCE	Claims Group-Dept Operati	60.00			60.00		60.00			-		60.00
		REWARDS_OE_LABOR_RE	Claims Group-Dept Operati	(562,226.28)			(562,226.28)		(562,226.28)			-		(562,226.28)
		INVESTMENT_RECOVERY	Claims Group-Dept Operati	(101.68)	(23.64)	(13.86)	(139.18)		(115.54)			(23.64)		(139.18)
		INVENTORY_MGMT	Claims Group-Dept Operati	(335.41)	(77.98)	(45.72)	(459.11)		(381.13)			(77.98)		(459.11)
	AG1050	INSURANCE	Claims	(0.00)			(0.00)		(0.00)			-		(0.00)
		REWARDS_OE_LABOR_RE	Claims	5,061.90			5,061.90		5,061.90			-		5,061.90
		NON_DEPARTMENTAL	Claims	36,472.83			36,472.83		36,472.83			-		36,472.83
00036 Total				4,507,074.83	##########	997,820.03	6,798,911.67	2,465,490.99	2,983,717.83	55,686.04	857,296.06	430,465.39	6,255.36	6,798,911.67
00049	AG0282	CLAIMS	Claims-Liability - Auto Only	49.00			49.00		49.00			-		49.00
00049 Total				49.00			49.00	-	49.00	-	-	-	-	49.00
00099	AG0485	CORPORATE_COMM	Provide Safety & Health Se	3,557.36	828.40	487.31	4,873.07			4,044.67			828.40	4,873.07
		HR_BUS_PARTNERS	Provide Safety & Health Se	568.10	132.27	77.83	778.20			645.93			132.27	778.20
		INTEGRATED_HEALTH	Provide Safety & Health Se	8,408.54	1,609.08	1,108.82	11,126.44			9,517.36			1,609.08	11,126.44
		SAFETY_SERVICES	Provide Safety & Health Se	14,569.49	3,392.90	1,995.85	19,958.24			16,565.34			3,392.90	19,958.24
	AG0271	INSURANCE	U.S. Insurance-Liability	293,393.01	68,325.35	40,191.09	401,909.45	333,584.10			68,325.35			401,909.45
	AG0276	INSURANCE	U.K. Insurance-Property	18,685.00	(4,854.00)	(2,855.00)	10,976.00	15,830.00			(4,854.00)			10,976.00
	AG0281	CLAIMS	Claims-Liability - Excl. Auto	2,917.66	679.50	399.58	3,996.74		3,317.24			679.50		3,996.74
	AG0283	CLAIMS	Claims-Accrual (Reserve)	24,600.19	5,728.85	3,370.22	33,699.26		27,970.41			5,728.85		33,699.26
	AG0289	ENERGY_SOLUTION_SERV	Claims Group-Dept Operati	28.17	6.56	3.86	38.59		32.03			6.56		38.59
		INSURANCE	Claims Group-Dept Operati	7,166.54	1,668.97	981.67	9,817.18		8,148.21			1,668.97		9,817.18
		CLAIMS	Claims Group-Dept Operati	83.37	19.42	11.42	114.21		94.79			19.42		114.21
00099 Total				373,977.43	77,537.30	45,772.65	497,287.38	349,414.10	39,562.68	30,773.30	63,471.35	8,103.30	5,962.65	497,287.38
Grand Total				**4,881,101.26**	**##########**	**1,043,592.68**	**7,296,248.05**	**2,814,905.09**	**3,023,329.51**	**86,459.34**	**920,767.41**	**438,568.69**	**12,218.01**	**7,296,248.05**

NMPC
Summary of Claims and Insurance Premiums
Charged in Expense type 400 to Company 36
By Electric and Gas

Fiscal Yr	(All)	**Injuries and Damages**
Regulatory Acc	(All)	
Regulatory Acc	(All)	
Period	(All)	
Business Unit	00036	
Jrnl Id	(All)	
Expense Type	400	
Chrg Dept L3	(All)	
Chrg Dept L2	(All)	

Sum of Posted Jrnl $				Segment					**Electric**				**Gas**		
Orig Business	**Activity**	Chrg Dept L4	**Activity Descr**	DIST	GAS	TRAN	Grand Total	Costs associated with Insurance	**Costs associated with Claims**	Costs associated with All Other		Costs associated with Insurance	**Costs associated with Claims**	Costs associated with All Other	Total
00010	AG1050	REWARDS_OE_LABOR_REL	Claims	44,248.26	10,304.38	6,061.41	60,614.05			50,309.67				10,304.38	60,614.05
00010 Total				44,248.26	10,304.38	6,061.41	60,614.05	-	-	50,309.67	#	-	-	10,304.38	60,614.05
00036	AG0235	LEGAL_SERVICES	General Legal Claims	46,036.54	122.98	72.34	46,231.86		46,108.88				122.98		46,231.86
	AG0485	INTEGRATED_HEALTH	Provide Safety & Health Servic	16,185.11	2,063.20	1,213.62	19,461.93			17,398.73				2,063.20	19,461.93
		LEGAL_SERVICES	Provide Safety & Health Servic	300.00			300.00			300.00				-	300.00
		PUBLIC_AFFAIRS	Provide Safety & Health Servic	36.45	7.47		43.92			36.45				7.47	43.92
		SAFETY_SERVICES	Provide Safety & Health Servic	5,128.30	1,126.61	662.75	6,917.66			5,791.05				1,126.61	6,917.66
	AG0271	ENVIRONMENTAL	U.S. Insurance-Liability	4,118.59			4,118.59	4,118.59				-			4,118.59
		INSURANCE	U.S. Insurance-Liability	1,924,406.20	494,101.32	302,615.49	2,721,123.01	2,227,021.69				494,101.32			2,721,123.01
	AG0276	INSURANCE	U.K. Insurance-Property	720,849.60	167,869.08	98,746.50	987,465.18	819,596.10				167,869.08			987,465.18
	AG0281	NETWORK_STRAT_ELEC	Claims-Liability - Excl. Auto	337.56			337.56		337.56				-		337.56
		OPS_&_CONSTRUCT-NYUP	Claims-Liability - Excl. Auto		137.70		137.70		-				137.70		137.70
		US_TREASURY	Claims-Liability - Excl. Auto	5,644.15			5,644.15		5,644.15				-		5,644.15
		CLAIMS	Claims-Liability - Excl. Auto	1,327,417.74	171,621.19	8,063.38	1,507,102.31		1,335,481.12				171,621.19		1,507,102.31
	AG0282	US_TREASURY	Claims-Liability - Auto Only	(1,264.47)			(1,264.47)		(1,264.47)				-		(1,264.47)
		CLAIMS	Claims-Liability - Auto Only	296,693.93	29,512.53		326,206.46		296,693.93				29,512.53		326,206.46
	AG0283	CLAIMS	Claims-Accrual (Reserve)	2,058,805.00	523,425.00	907,270.00	3,489,500.00		2,966,075.00				523,425.00		3,489,500.00
	AG0289	INSURANCE	Claims Group-Dept Operations	696.61			696.61		696.61				-		696.61
00036 Total				6,405,391.31	1,389,987.08	1,318,644.08	9,114,022.47	3,050,736.38	4,649,772.78	23,526.23	#	661,970.40	724,819.40	3,197.28	9,114,022.47
00099	AG0485	CORPORATE_COMM	Provide Safety & Health Servic	2,455.02	571.69	336.31	3,363.02			2,791.33				571.69	3,363.02
		CUST_OPERATIONS	Provide Safety & Health Servic	57.25	13.33	7.84	78.42			65.09				13.33	78.42
		HR_BUS_PARTNERS	Provide Safety & Health Servic	51.65	12.02	7.08	70.75			58.73				12.02	70.75
		INTEGRATED_HEALTH	Provide Safety & Health Servic	1,305.49	289.48	170.29	1,765.26			1,475.78				289.48	1,765.26
		NETWORK_STRAT_ELEC	Provide Safety & Health Servic	208.90	48.65	28.62	286.17			237.52				48.65	286.17
		SAFETY_SERVICES	Provide Safety & Health Servic	9,607.85	2,237.41	1,316.12	13,161.38			10,923.97				2,237.41	13,161.38
		TRANS_PLANNING	Provide Safety & Health Servic	67.03	15.61	9.18	91.82			76.21				15.61	91.82
	AG0234	DISTRIBUTION_SUPPORT	Environmental Safety Audit	291.94	67.99	39.99	399.92			331.93				67.99	399.92
	AG0271	INSURANCE	U.S. Insurance-Liability	165,968.66	(495.90)	(291.47)	165,182.29	165,678.19				(495.90)			165,182.29
	AG0276	INSURANCE	U.K. Insurance-Property	99,589.46	23,192.59	13,641.85	136,423.90	113,231.31				23,192.59			136,423.90
	AG0283	CLAIMS	Claims-Accrual (Reserve)	502.05	122.20	69.50	693.75		571.55				122.20		693.75
	AG0289	INSURANCE	Claims Group-Dept Operations	4,299.97	950.14	588.92	5,839.03		4,888.89				950.14		5,839.03
		CLAIMS	Claims Group-Dept Operations	29.04	6.77	3.98	39.79		33.02				6.77		39.79
00099 Total				284,435.31	27,031.98	15,928.21	327,395.50	278,909.50	5,493.46	15,960.56	#	22,696.69	1,079.11	3,256.18	327,395.50
Grand Total				6,734,074.88	1,427,323.44	1,340,633.70	9,502,032.02	3,329,645.88	4,655,266.24	39,796.46	#	684,667.09	725,898.51	16,757.84	9,502,032.02

NMPC
Summary of Claims and Insurance Premiums
Charged in Expense type 400 to Company 36
By Electric and Gas

Period	(All)	Injuries and Damages
Fiscal Yr	(All)	HTY ending Sept 30, 2007
Regulatory Acct Descr	(All)	
Regulatory Acct	(All)	
Business Unit	00036	
Jrnl Id	(All)	
Expense Type	400	
Chrg Dept L3	(All)	
Chrg Dept L2	(All)	

Sum of Posted Jrnl $				Segment				Electric			Gas			
Orig Business Unit	Activity	Chrg Dept L4	Activity Descr	DIST	GAS	TRAN	Grand Total	Costs associated with Insurance	Costs associated with Claims	Costs associated with All Other	Costs associated with Insurance	Costs associated with Claims	Costs associated with All Other	Total
00001	AG0271	INSURANCE	U.S. Insurance-Liability	(13,752.09)	(3,202.54)	(1,883.85)	(18,838.48)	(15,635.94)			(3,202.54)			(18,838.48)
00001 Total				(13,752.09)	(3,202.54)	(1,883.85)	(18,838.48)	(15,635.94)	-	-	(3,202.54)	-	-	(18,838.48)
00005	AG0282	CLAIMS	Claims-Liability - Auto Only	2,431.00			2,431.00		2,431.00			-		2,431.00
00005 Total				2,431.00			2,431.00	-	2,431.00	-	-	-	-	2,431.00
00010	AG0271	INSURANCE	U.S. Insurance-Liability	(2,390.54)			(2,390.54)	(2,390.54)			-			(2,390.54)
00010 Total				(2,390.54)			(2,390.54)	(2,390.54)	-	-	-	-	-	(2,390.54)
00036	AG0235	LEGAL_SERVICES	General Legal Claims	50,546.93	215.16	25.68	50,787.77		50,572.61			215.16		50,787.77
	AG0485	INTEGRATED_HEALTH	Provide Safety & Health Servic	13,157.00	2,524.67	1,485.16	17,166.83			14,642.16			2,524.67	17,166.83
		LEGAL_SERVICES	Provide Safety & Health Servic	219.00	51.00	30.00	300.00			249.00			51.00	300.00
		SAFETY_SERVICES	Provide Safety & Health Servic	12,341.59	1,567.31	921.97	14,830.87			13,263.56			1,567.31	14,830.87
	AG0271	INSURANCE	U.S. Insurance-Liability	711,465.20	243,147.30	154,130.47	1,108,742.97	665,595.67			243,147.30			1,108,742.97
	AG0273	INSURANCE	U.S. Insurance-Workers Comp	521,400.72	121,422.09	71,424.78	714,247.59	592,825.50			121,422.09			714,247.59
	AG0275	INSURANCE	U.K. Insurance-Liability	233,410.37	54,636.51	32,139.15	320,186.03	265,549.52			54,636.51			320,186.03
	AG0276	INSURANCE	U.K. Insurance-Property	874,126.69	98,143.47	57,731.44	1,030,001.60	931,858.13			98,143.47			1,030,001.60
	AG0281	CUST_OPERATIONS	Claims-Liability - Excl. Auto	1,870.65	1,064.50		2,935.15		1,870.65			1,064.50		2,935.15
		OPS_&_CONSTRUCT-NY	Claims-Liability - Excl. Auto		1,064.50		1,064.50		-			1,064.50		1,064.50
		US_TREASURY	Claims-Liability - Excl. Auto	3,736.09	75.00		3,811.09		3,736.09			75.00		3,611.09
		CLAIMS	Claims-Liability - Excl. Auto	1,300,533.32	106,426.92	7,362.28	1,414,322.52		1,307,895.60			106,426.92		1,414,322.52
	AG0282	US_TREASURY	Claims-Liability - Auto Only	1,030.94			1,030.94		1,030.94			-		1,030.94
		CLAIMS	Claims-Liability - Auto Only	464,642.82	6,214.32	500.00	471,357.14		465,142.82			6,214.32		471,357.14
	AG0283	CLAIMS	Claims-Accrual (Reserve)	6,136,500.00	652,500.00	960,599.76	7,749,599.76		7,097,099.76			652,500.00		7,749,599.76
	AG1050	PUBLIC_AFFAIRS	Claims	54.75	12.75	7.50	75.00		62.25			12.75		75.00
00036 Total				10,325,036.07	1,289,065.50	1,286,358.19	12,900,459.76	2,655,828.82	8,927,410.72	28,154.72	517,349.37	767,573.15	4,142.98	##########
00099	AG0485	CUST_OPERATIONS	Provide Safety & Health Servic	160.90	37.47	22.04	220.41			182.94			37.47	220.41
		EMPL_SERV_&_ADMIN	Provide Safety & Health Servic	1,029.59	239.76	141.04	1,410.39			1,170.63			239.76	1,410.39
		HR_BUS_PARTNERS	Provide Safety & Health Servic	349.27	81.35	47.85	478.47			397.12			81.35	478.47
		INTEGRATED_HEALTH	Provide Safety & Health Servic	388.36	42.43	24.97	455.76			413.33			42.43	455.76
		LEARNING_DEVELOP	Provide Safety & Health Servic	3,953.70	920.70	541.60	5,416.00			4,495.30			920.70	5,416.00
		SAFETY_SERVICES	Provide Safety & Health Servic	29,003.74	6,656.69	3,915.84	39,576.27			32,919.58			6,656.69	39,576.27
	AG0271	INSURANCE	U.S. Insurance-Liability	838,236.55	230,223.94	103,347.30	1,171,807.79	941,583.65			230,223.94			1,171,607.79
	AG0273	INSURANCE	U.S. Insurance-Workers Comp	84,049.63	19,572.37	11,513.55	115,135.55	95,563.18			19,572.37			115,135.55
	AG0275	INSURANCE	U.K. Insurance-Liability	794,451.58	184,998.57	108,825.43	1,088,275.58	903,277.01			184,998.57			1,088,275.58
	AG0276	INSURANCE	U.K. Insurance-Property	76,207.51	17,745.72	10,439.02	104,392.25	86,646.53			17,745.72			104,392.25
	AG0281	CLAIMS	Claims-Liability - Excl. Auto	30,219.24	4,176.47	159.25	34,554.96		30,378.49			4,176.47		34,554.96
	AG0282	US_TREASURY	Claims-Liability - Auto Only	(10,658.39)	(75.00)		(10,733.39)		(10,658.39)			(75.00)		(10,733.39)
		CLAIMS	Claims-Liability - Auto Only	2,783.93	219.54		3,003.47		2,783.93			219.54		3,003.47
	AG0283	CLAIMS	Claims-Accrual (Reserve)	751,980.00	175,120.00	103,020.00	1,030,120.00		655,000.00			175,120.00		1,030,120.00
	AG0289	INSURANCE	Claims Group-Dept Operations	3,044.96	685.45	301.48	4,031.89		3,346.44			685.45		4,031.89
		CLAIMS	Claims Group-Dept Operations	112.80	26.27	15.45	154.52		128.25			26.27		154.52
00099 Total				2,605,313.37	640,671.73	342,314.82	3,588,299.92	2,027,070.57	880,978.72	39,578.90	452,540.60	180,152.73	7,978.40	3,588,299.92
Grand Total				12,916,637.81	1,926,534.69	1,626,789.16	16,469,961.66	**4,664,872.91**	**9,810,820.44**	**67,733.62**	**966,687.43**	**947,725.88**	**12,121.38**	**##########**

NMPC
Summary of Claims and Insurance Premiums
Charged in Expense type 400 to Company 36
By Electric and Gas

Injuries and Damages
HTY ending Sept 30, 2008

Fiscal Yr	(All)
Regulatory Acct Des	(All)
Regulatory Acct	(All)
Business Unit	00036
Jrnl Id	(All)
Expense Type	400
Chrg Dept L3	(All)
Chrg Dept L2	(All)

Sum of Posted Jrnl $				Segment				Electric			Gas			
								Costs associated with Insurance	**Costs associated with Claims**	Costs associated with All Other	Costs associated with Insurance	**Costs associated with Claims**	Costs associated with All Other	
Orig Business Unit	**Activity**	Chrg Dept L4	**Activity Descr**	DIST	GAS	TRAN	Grand Total							Total
00005	AG0485	INTEGRATED_HEALTH	Provide Safety & Health Servi	191.63	44.63	26.25	262.51			217.88			44.63	262.51
		SAFETY_SERVICES	Provide Safety & Health Servi	(191.63)	(44.63)	(26.25)	(262.51)			(217.88)			(44.63)	(262.51)
	AG0281	CLAIMS	Claims-Liability - Excl. Auto	(316.50)			(316.50)		(316.50)			-		(316.50)
00005 Total				(316.50)	-	-	(316.50)	-	(316.50)	-	-	-	-	(316.50)
00036	AG0235	LEGAL_SERVICES	General Legal Claims	23,481.13			23,481.13		23,481.13			-		23,481.13
	AG0485	CUST_OPERATIONS	Provide Safety & Health Servi	1,205.86	167.24	98.38	1,471.48			1,304.24			167.24	1,471.48
		INTEGRATED_HEALTH	Provide Safety & Health Servi	8,488.51	1,551.92	912.89	10,953.32			9,401.40			1,551.92	10,953.32
		NETWORK_STRAT_ELEC	Provide Safety & Health Servi	43.80	10.20	6.00	60.00			49.80			10.20	60.00
		SAFETY_SERVICES	Provide Safety & Health Servi	11,178.06	1,805.08	1,061.81	14,044.95			12,239.87			1,805.08	14,044.95
	AG0271	INSURANCE	U.S. Insurance-Liability	(277,702.09)	(129,540.00)	(39,697.39)	(446,939.48)	(317,399.48)			(129,540.00)			(446,939.48)
	AG0276	INSURANCE	U.K. Insurance-Property	274,328.38	169,304.97	99,591.16	543,224.51	373,919.54			169,304.97			543,224.51
	AG0281	CUST_OPERATIONS	Claims-Liability - Excl. Auto	7,128.94	647.59		7,776.53		7,128.94			647.59		7,776.53
		OPS_&_CONSTRUCT-NY	Claims-Liability - Excl. Auto		135.00		135.00		-			135.00		135.00
		US_TREASURY	Claims-Liability - Excl. Auto	5,575.86	506.83	298.14	6,380.83		5,874.00			506.83		6,380.83
		CLAIMS	Claims-Liability - Excl. Auto	##########	64,226.26	4,030.80	1,429,277.30		##########			64,226.26		##########
	AG0282	CUST_OPERATIONS	Claims-Liability - Auto Only		650.00		650.00		-			650.00		650.00
		CLAIMS	Claims-Liability - Auto Only	221,504.43	21,502.15	24.90	243,031.48		221,529.33			21,502.15		243,031.48
	AG0283	CLAIMS	Claims-Accrual (Reserve)	##########	65,000.00	(500,000.00)	3,533,970.32		##########			65,000.00		##########
	AG0289	INSURANCE	Claims Group-Dept Operations	129.20	6.80	4.00	140.00		133.20			6.80		140.00
		CLAIMS	Claims Group-Dept Operations	832.20	193.80	114.00	1,140.00		946.20			193.80		1,140.00
	AG1050	REWARDS_OE_LABOR_R	Claims	(9,934.50)	(2,313.51)	(1,360.89)	(13,608.90)		(11,295.39)			(2,313.51)		(13,608.90)
00036 Total				##########	193,854.33	(434,916.20)	5,355,188.47	56,520.06	##########	22,995.31	39,764.97	150,554.92	3,534.44	##########
00048	AG0281	CLAIMS	Claims-Liability - Excl. Auto		(16,811.95)		(16,811.95)		-			(16,811.95)		(16,811.95)
00048 Total					(16,811.95)		(16,811.95)	-	-	-	-	(16,811.95)	-	(16,811.95)
00099	AG0485	CONSTRUCT_DELIVERY	Provide Safety & Health Servi	12.57	2.93	1.72	17.22			14.29			2.93	17.22
		CORPORATE_COMM	Provide Safety & Health Servi	2,270.25	528.73	311.00	3,109.98			2,581.25			528.73	3,109.98
		CUST_OPERATIONS	Provide Safety & Health Servi	4,436.04	911.96	536.44	5,884.44			4,972.48			911.96	5,884.44
		ENERGY_SOLUTION_SE	Provide Safety & Health Servi	969.85	225.85	132.85	1,328.55			1,102.70			225.85	1,328.55
		INTEGRATED_HEALTH	Provide Safety & Health Servi	978.63	(50.55)	(29.73)	898.35			948.90			(50.55)	898.35
		LEARNING_DEVELOP	Provide Safety & Health Servi	1,030.65	240.00	141.18	1,411.83			1,171.83			240.00	1,411.83
		REWARDS_OE_LABOR_R	Provide Safety & Health Servi	34.04	7.93	4.66	46.63			38.70			7.93	46.63
		SAFETY_SERVICES	Provide Safety & Health Servi	44,867.81	8,137.87	4,912.45	57,918.13			49,780.26			8,137.87	57,918.13
	AG0271	INSURANCE	U.S. Insurance-Liability	##########	523,003.99	263,529.91	2,710,273.65	##########			523,003.99			##########
	AG0273	INSURANCE	U.S. Insurance-Workers Comp	788,916.29	183,720.30	108,070.73	1,080,707.32	896,987.02			183,720.30			##########
		REWARDS_OE_LABOR_R	U.S. Insurance-Workers Comp	-	-	-	-	-			-			-
	AG0275	INSURANCE	U.K. Insurance-Liability	589,573.66	137,305.97	80,766.88	807,646.51	670,340.54			137,305.97			807,648.51
	AG0276	INSURANCE	U.K. Insurance-Property	681,487.86	158,699.79	93,353.29	933,540.94	774,841.15			158,699.79			933,540.94
	AG0279	INSURANCE	Insurance Group-Dept Operati	18.39	4.28	2.52	25.19	20.91			4.28			25.19
	AG0281	CLAIMS	Claims-Liability - Excl. Auto	9,301.19	1,654.58		10,955.77		9,301.19			1,654.58		10,955.77
	AG0282	CLAIMS	Claims-Liability - Auto Only	4,414.95			4,414.95		4,414.95			-		4,414.95
	AG0283	CLAIMS	Claims-Accrual (Reserve)	22,559.40	5,253.60	3,090.60	30,903.60		25,650.00			5,253.60		30,903.60
	AG0289	INSURANCE	Claims Group-Dept Operations	1,214.08	243.55	120.81	1,578.44		1,334.89			243.55		1,578.44
		CLAIMS	Claims Group-Dept Operations	338.19	76.37	34.66	449.22		372.85			76.37		449.22
	AG1050	REWARDS_OE_LABOR_R	Claims	9,934.50	2,313.51	1,360.89	13,608.90		11,295.39			2,313.51		13,608.90
00099 Total				##########	##########	556,340.86	5,664,719.62	##########	52,369.27	60,610.41	##########	9,541.61	10,004.72	##########
00431	925010	INSURANCE	Om-A&G-Empl Inj&Dam	22,897.52	6,361.07	3,532.63	32,791.22	26,430.15			6,361.07			32,791.22
00431 Total				22,897.52	6,361.07	3,532.63	32,791.22	26,430.15	-	-	6,361.07	-	-	32,791.22
Grand Total				##########	##########	124,957.29	11,035,570.86	##########	##########	83,605.72	##########	143,284.58	13,539.16	##########

Date of Request: March 10, 2010
Due Date: March 22, 2010

Request No. AAE-14
NMPC Req. No. NM 200 DPS 130

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Allison Esposito

TO: Revenue Requirement Panel

Request:

1. Pages 79-80 of the Revenue Requirements Panel testimony discuss the Company's inclusion of non-utility plant costs in the SIR deferral account. Please provide a list of non-utility properties for which the Company has included remediation costs in the SIR deferral. For each property, please provide the following:

A. The location of the property
B. The total amount of costs that have been included in the SIR deferral, broken out by expense type and acquisition cost.
C. The specific wording within each Commission Order that allows the Company to defer these incremental costs associated with remediation including current O&M and remediation.
D. The cost/benefit analysis showing that the reduction in overall remediation expenses associated with the purchase exceed the costs of the purchase and on-going remediation and maintenance of the property.

2. Page 79, lines 16-17 of the RRP testimony state that certain non-utility remediation costs were included in the SIR deferral account "pursuant to agreements with Staff." Please fully explain what these agreements with Staff are and when they were reached. In addition, please provide copies of every such agreement.

Response:

Responses to Items 1.A, 1.B, and 1.D are provided by site below.

1. C. For clarity and in reference to SIR projects, O&M is a technical term which refers to "Operations and Maintenance" of a site remedy after remediation is completed (sampling, repair of soil caps, maintenance of groundwater treatment systems, etc.) rather than accounting terminology.

The Commission Order allows recovery of costs associated with site investigation and remediation. Pursuant to environmental laws and Orders on Consent with the NYS DEC and US EPA, Niagara Mohawk is required to address contamination associated with former utility operations, regardless of where the contamination is currently located. For example, former MGP plants operated by Niagara Mohawk and its predecessors operated in a period spanning the 1840's to 1960's. The formerly owned properties were either sold after the plants were decommissioned or were converted to other utility use, such as gas regulator stations, operations centers, etc. Contamination from the plants may have migrated onto adjacent properties or water bodies; were transported to remote locations; and/or were deposited on other properties, or water bodies. Therefore, Niagara Mohawk is required to address contamination from the former MGP operations located on property owned by Niagara Mohawk (utility and non-utility property), as well as property not owned by Niagara Mohawk.

During the investigation of a property that is not owned by Niagara Mohawk, the property is initially evaluated (following soil and/or water sampling results) to determine if the current use can be maintained. The NYS DEC has generic concentration thresholds that are protective of industrial, commercial, restricted residential, and unrestricted residential use. If the sampling indicates that concentrations in excess of unrestricted use are attributable to former MGP operations, the future (or current) property use will need to be restricted. Property owners are often either unwilling to place deed restrictions on their property (as required by the NYS DEC in the event that impacted material will remain following remediation), or unable to, considering the current property use (i.e., existing residence). Since the Company has no legal power to enforce a deed restriction on an unwilling property owner, the Company must remediate the site to unrestricted use levels. In those situations, a purchase analysis is conducted to determine if it is cost effective to purchase the property from the owner, and remediate the site to a lower cleanup level (such as commercial or industrial), or to compensate the property owner (typically the property value) to maintain a deed restriction on the land.

1. A, B, and D

The non-utility properties listed, for which the Company has charged related remediation costs in the SIR deferral, are listed below along with responses to questions A., B., and D. The total costs that have been included in the SIR deferral are listed below by Expense Type for each non-utility property, and are total deferral costs-to-date charged to the SIR site. The Company tracks SIR spending by site, not by individual parcels of land within the site.

<u>Cohoes</u>
A. Address: 0 Linden Street
B. Costs: Acquisition cost $442,577
Deferral Costs: See Attachment - "Site Expense Type Totals Report.xls"
D. Purchase Analysis: See Attachment - "Site Expense Type Totals Report.xls"

<u>Fort Edward</u>

B. Cost: Acquisition cost $70,000
Deferral Costs: See Attachment - "Site Expense Type Totals Report.xls"
D. Purchase Analysis: See attached

Rome (Kingsley Ave)
A. Address: Voci and Vecchio Properties, adjacent to the site
B. Cost: Acquisition costs: $80,000 (Voci) and $74,000 (Vecchio) respectively.
Note: The recent Vecchio property purchase cost is currently residing in the SIR deferral, and is temporarily included in the SIR Rome (Kingsley Ave) spending total. A copy of the JE Request to move this cost to FERC 121000 is attached.
Deferral Costs: See Attachment - "Site Expense Type Totals Report.xls"
D. Purchase Analysis: See attached

Rome (Jay & Madison) MGP
A. Address: Woodrow Avenue
B. Cost: Acquisition cost $190,000
Deferral Costs: See Attachment - "Site Expense Type Totals Report.xls"
D. Purchase Analysis: See attached

Saratoga Springs
A. Address: Excelsior Avenue
B. Cost: Acquisition cost $1,003,000
Deferral Costs: See Attachment - "Site Expense Type Totals Report.xls"
D. Purchase Analysis: Due to the presence of contamination relating to past MGP operations, Niagara Mohawk was required to remediate the property. The property was purchased in order to lower the cleanup standards to commercial standards (agreed to by US EPA) and enable Niagara Mohawk to retain control of the property during the remedial program versus a more expensive remedy which would have involved cleanup to residential standards had the property not been purchased.

Note D: For those sites identified above, the purchase analysis documentation is provided as Attachment "PSC AAE-14 Item 1 Cost-Benefit.pdf".

2. The "agreements with Staff" mentioned in the RRP testimony in connection with certain non-utility remediation costs included in the SIR deferral account refer to the following:

1993 Final Commission Order

In the 1993 Final Commission Order (cases 93-G-0162, 93-E-0376, and 93-E-0378) it is stated "Judge Lynch endorsed staff's proposal that Niagara Mohawk be required in all future rate cases to justify affirmatively in pre-filed direct testimony and exhibits the recovery of site investigation and remediation (SIR) costs for non-utility (also known as "other physical property") sites."

November 6, 2003 meeting with PSC staff and Email Correspondence Spanning June 2004 through April 2008

In the November 2003 meeting, Niagara Mohawk identified its legal obligations to remediate contaminated sites and requested PSC Staff guidance us to which property purchase costs should be included in the deferral. The email correspondence presents a dialogue between Niagara Mohawk and PSC staff, culminating with a suggestion regarding land purchases for the SIR program and use of the deferral for those purchases. In summary, the April 21, 2008 email from Mr. Visalli to Mr. Fletcher suggests that the Company put "qualifying" land costs in the SIR deferral. Mr. Visalli also goes on to suggest that along with each purchase, that a cost/benefit analysis be documented (and therefore in the Company's opinion based on cost effectiveness is deemed a qualifying cost).

An excerpt of the 1993 Final Commission Order (relating to the statement above) the above-referenced emails between Niagara Mohawk and PSC Staff are provided in Attachment "PSC AAE-14 Item 2 Agreement.pdf".

Name of Respondent:

Brian Stearns
Michael Bogan

Date of Reply:

March 22, 2010

Niagara Mohawk

David H. King
Executive Director, Environmental Affairs

Phone: (315) 428-5127
FAX (315) 428-3549
E-mail: kingD@nimo.com

September 23, 1998

Mr. George B. Waters
President and Editor
Rome Sentinel Company
333 W. Dominick Street
P.O. Box 471
Rome, N.Y. 13440-0471

Re: Proposed AutoZone, Inc. Redevelopment Project on Rome Sentinel Property

Dear Mr. Waters:

I have been asked to respond to your letter of September 10, 1998 letter to Mr. William Davis, Chairman and CEO of Niagara Mohawk, regarding the above-referenced project.

It is unfortunate that Rome Sentinel's property has been impacted by residual byproducts or constituents associated with the former coal gas manufacturing plant (MGP) which operated many decades ago on Niagara Mohawk's adjacent property. As you may be aware, this former MGP site is one of twenty-three such sites located within my company's service territory which are subject to a multi-site Order on Consent with the New York State Department of Environmental Conservation (NYSDEC).

As is the case for most of Niagara Mohawk's other MGP sites, this former Rome MGP site is subject to an ongoing site investigation effort which, depending upon the results of investigations, remedial evaluations, and reviews by affected landowners, the public, and the NYSDEC/New York State Department of Health (NYSDOH), will likely lead to remedial actions. Please be assured that we have attempted to expedite the traditional regulatory process in order to support AutoZone, Inc.'s proposed redevelopment of Rome Sentinel's property.

The NYSDEC provided us with comments on our proposed Interim Remedial Measures Excavation Plan for Rome Sentinel's property on September 15, 1998. We will share these comments with your legal counsel, Ms. Doreen Simmons, Esq. of Hancock & Estabrook, quickly respond to the NYSDEC, finalize the work plan, and competitively procure the services of a remedial contractor to implement the plan. If we receive timely approval of these plans, we should be able to perform the excavation work at your property in mid- to late October, 1998.

In an attempt to further address Rome Sentinel's and AutoZone, Inc.'s concerns about the environmental impacts identified on your property, we asked the NYSDEC (via a July 20, 1998 letter) to issue a letter indicating that the NYSDEC will rely upon our commitment (and obligations) to address MGP contamination on the subject property and hold harmless Rome Sentinel or the prospective purchaser.

Even after we perform the proposed excavation activities, some residual groundwater contamination will likely remain on the property and, per NYSDEC requirements, the site will be subjected to long-term monitoring, deed restrictions, and, as required, potential additional remedial actions aimed at addressing groundwater contamination. AutoZone, Inc. or any other prospective owners of this property would need to adhere to deed restrictions on the property to prevent potential future use of site groundwater and residential use. This should not technically nor legally prohibit AutoZone, Inc.'s proposed commercial use of this property. This situation is similar to those experienced by the developers of most brownfield sites.

At the close of your letter to Mr. Davis, you suggested that "There should be no further delay in the purchase of it..." (your property) "...by NMPC plus reimbursement of our legal and other costs." Neither Rome Sentinel nor your counsel has made any prior, formal requests for Niagara Mohawk to purchase your property. Should Rome Sentinel wish to pursue such a transaction, we are willing to consider it on the basis of achieving fair and reasonable economic and legal terms, and on the basis of continuing to promote the property's redevelopment by AutoZone, Inc. or by some other commerical developer. Should Rome Sentinel not desire to pursue such a transaction with Niagara Mohawk, we will continue to respond to your concerns and to promote the proposed redevelopment effort the very best that we can.

To move this process forward, I suggest that you have your counsel call Mr. Charles Sullivan, Esq. of the NYSDEC and Niagara Mohawk's Mr. William Weiss, Esq. to discuss how best to continue promoting AutoZone, Inc.'s proposed project at your property.

Sincerely,

David H. King

David H. King
Executive Director, Environmental Affairs

Final Commission Order

Henceforth, Niagara Mohawk will have the same obligation as other New York utilities to quantify how implementation of management audit recommendations has affected rate year revenue requirement.[1]

Site Investigation and Remediation Cost

Judge Lynch endorsed staff's proposal that Niagara Mohawk be required in all future rate cases to justify affirmatively in prefiled direct testimony and exhibits the recovery of site investigation and remediation (SIR) costs for nonutility (also known as "other physical property") sites. He also agreed with Niagara Mohawk that SIR costs for these sites should be recovered in full when the property is actually used for utility purposes, even if it is otherwise recorded on the company's books. Finally, the Judge recommended against CPB's proposal that Niagara Mohawk be required to absorb 20% of all SIR costs.[2]

Niagara Mohawk asks for clarification that it will be required only to file such documentation as is reasonably available to it at the time of its rate case filing and that

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1 See Cases 92-E-1055 et al., Central Hudson Gas & Electric Corporation - Rates, Opinion No. 94-3 (issued February 11, 1994), mimeo p. 66 and Case 93-G-0002, Long Island Lighting Company - Rates, Opinion No. 92-23 (issued December 23, 1993), mimeo p. 31.

2 R.D., pp. 105.

Willard, Charles F.

From: Fletcher, James J.
Sent: Thursday, June 03, 2004 3:42 PM
To: Willard, Charles F.
Subject: RE: SIR property purchases

No. I would keep a copy of the email that I copied Bob on. If he has a concern he should express it upon receiving the e-mail.

-----Original Message-----
From: Willard, Charles F.
Sent: Thursday, June 03, 2004 9:33 AM
To: Fletcher, James J.
Subject: RE: SIR property purchases

Jim,

Will we receive anything in writing back from Bob? If so, any idea on timing?

Chuck

-----Original Message-----
From: Fletcher, James J.
Sent: Wednesday, June 02, 2004 9:53 AM
To: Willard, Charles F.
Cc: 'denise_gerbsch@dps.state.ny.us'; robert_visalli@dps.state.ny.us
Subject: RE: SIR property purchases

Talked to Bob Visalli. He said that the Staff agreed with the idea of purchasing sites to mitigate clean up costs, ***as long as the purchase is cost justified.***

-----Original Message-----
From: Willard, Charles F.
Sent: Wednesday, May 26, 2004 8:19 AM
To: Fletcher, James J.
Subject: SIR property purchases

Jim,

Any word back from the PSC regarding the purchase of property by SIR? We are currently evaluating the purchase of two properties.

Chuck

Stearns, Brian M.

Subject: FW: land purchases for the SIR program / SIR deferral

From: robert_visalli@dps.state.ny.us [mailto:robert_visalli@dps.state.ny.us]
Sent: Monday, April 21, 2008 10:34 AM
To: Fletcher, James J.
Cc: Willard, Charles F.; denise_gerbsch@dps.state.ny.us
Subject: RE: land purchases for the SIR program / SIR deferral

Jim,

Sorry for the delays. I think part of the delay is that we are not really sure what you are looking for from us. If it's for some kind of blanket pre-approval that all future land purchases for the SIR program are "good" deferral $$$ and not subject to future audit and possible disallowance, I don't think that will happen. I also don't think the Company or Staff wants a petition filed every time the Company wants to purchase land for SIR program purposes...................my suggestion is for the Company to just put "qualifying" land costs in the SIR deferral, and either attach the cost/benefit as part of that month's Attachment 11 filing or simply provide us the cost/benefit analysis separate from the Attachment 11 filing but at the same time the costs are recorded in the deferral account.

Personally, I think the timing of each cost/benefit analysis is important. I think it would be problematic for the Company to wait to see if we ask for the cost/benefit analyses as part of some future SIR deferral account audit, and, if we do, then the Company puts together some sort of cost/benefit analysis after the fact for these land purchases. Again, just an observation / suggestion.

Bottom line is that the Company has the burden of proof to show that each such purchase of land included in the SIR deferral account is cost beneficial. As such, the Company should do whatever it believes is the best course of action to protect its interests / investments.

Bob V

"Fletcher, James J."
<James.Fletcher@us.ngrid.com>

04/19/2008 06.39 PM

To <denise_gerbsch@dps.state.ny.us>
cc <robert_visalli@dps.state.ny.us>, "Willard, Charles F." <Charles.Willard@us.ngrid.com>
Subject RE: land purchases for the SIR program / SIR deferral

I know everyone is much busier than we should be, and I'm trying not to be a pest - any word?

From: Fletcher, James J.
Sent: Wednesday, April 09, 2008 9:32 AM
To: 'denise_gerbsch@dps.state.ny.us'
Cc: 'robert_visalli@dps.state.ny.us'; Willard, Charles F.
Subject: RE: land purchases for the SIR program / SIR deferral

I believe the last time this was discussed, you were going to talk to Jane about how to proceed. If this is correct, can you bring us up to speed?

From: Fletcher, James J.
Sent: Monday, March 10, 2008 10:28 AM
To: 'denise_gerbsch@dps.state.ny.us'
Cc: 'robert_visalli@dps.state.ny.us'; Willard, Charles F.
Subject: RE: land purchases for the SIR program / SIR deferral

We purchased 3 properties for $624K.See my SIR analysis (the Excel spreadsheet)> Go to the tab called "prop pur". Two of the purchases were removed form the deferral, as shown on this tab. They were removed because in NE, they don't record purchases into a deferral, until the land is sold. A purchase of $65K remained in the deferral but should have been removed since my analysis.

I would like to talk about this. This issue is due to my inexperience in regulatory matters. As you can see form the attached email, I had the impression that we had "permission" to utilize this strategy. Since we talked several weeks ago, I contacted Rob Hoaglund, and asked him to talk to Jane about a potential filing. Jane was on vacation when I had this conversation.

Let me know when you want to talk.

From: denise_gerbsch@dps.state.ny.us [mailto:denise_gerbsch@dps.state.ny.us]
Sent: Friday, March 07, 2008 4:15 PM
To: Fletcher, James J.
Cc: robert_visalli@dps.state.ny.us
Subject: land purchases for the SIR program / SIR deferral

I'm looking over JEs now, and I came across this JE. We need to discuss this, as I'm not aware that you were given permission from the PSC to do land purchases as part of your SIR program / SIR deferral. Mike Bogan's e-mail dated 1/26/2007 indicates the company had recently received approval from the PC to charge SIR land purchases to the deferral. I don't know how many of these land purchases you have done, you might want to find out.

Denise A. Gerbsch
Office of Accounting, Finance and Economics
NYS Dept of Public Service
300 Erie Blvd West
Syracuse, NY 13202
Office: (315) 428-5308
Fax: (315) 428-5460
e-mail: denise_gerbsch@dps.state.ny.us

**** For your information: KeySpan is now part of National Grid.****

Date of Request: March 10, 2010
Due Date: March 22, 2010

Request No. RAV-55
NMPC Req. No. NM 202 DPS 132

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Rate Design, Customer and Markets Panel

Request:

Per Exhibit RDCM-4, Schedule 1, historic test year late payment charges (LPCs) were $15,093,100 and service classification (SC) revenues were $2,856,854,394. This results in an historic test year LPC:SC revenue ratio of 0.005283. Per Exhibit RDCM-4, Schedule 2, rate year 2011 LPCs are only forecasted to be $14,579,172 despite the fact that SC revenues are forecasted to increase to $3,046,063,116. This results in a rate year LPC:SC revenue ratio of only 0.004786.

A. Fully explain why the Company has assumed LPC will decline by 3.4% from the historic test year to the rate year even though SC revenues are forecasted to increase by 6.6% from the historic test year level to the rate year level.

1. Is the Company assuming customer will pay their bills in a more timely manner? If so, what is the basis for this assumption and what is the expected rate year cash flow enhancement?
2. Is the Company making some kind of normalization adjustment to the historic test year LPCs? If so, fully explain what the normalization adjustment is, why it is needed and provide documentary support from the Company's books which quantify the amount of the normalizing adjustment.

B. Fully explain why the rate year 2011 LPC forecast should not be 6.6% higher than the historic test year amount ($16,089,244 versus $15,093,100) considering SC revenues are forecasted to increase by 6.6% from the historic test year level to the rate year level.

C. Fully explain why the Company's 2012 LPC forecast on Exhibit RDCM-4, Schedule 3 increases from 2011 forecasted levels by the % increase in 2012 forecasted SC revenues over 2011 forecasted SC revenues, while the same relationship does not hold true for: (1) 2011 LPCs (i.e., by the % increase in 2011 forecasted SC revenues over historic test year SC revenues); or, depending on your answer to part A, (2) 2011 LPCs (i.e., by the % increase in 2011 forecasted SC revenues over normalized historic test year SC revenues).

Response:

A&B The historic test year LPC:SC revenue ratio is equal to .004786 as shown on Exhibit___RDCM-4, Schedule 5, Sheet 7. This ratio was developed using (in $000's) SC revenues of $2,834,349.1 as shown in Exhibit___RLW-5, plus Purchase of Receivables (POR) of $287,904.5 as shown in Exhibit___RLW-5, for total revenue of $3,122,253.7 as shown in Exhibit___RDCM-4, Schedule 5, Sheet 7.

C The SC revenues shown in Exhibit___RDCM-4, Schedule 1 in the amount of $2,856,854,394 include disputed station service and Borderline revenues, whereas, the SC revenues used to calculate the historic test year LPC:SC revenue ratios does not include disputed station service or Borderline revenues. The disputed station service revenues are not included in the calculation of the LPC:SC revenue ratio because although the Company was still billing these accounts during the historic test year, a monthly journal entry reversed both principal and late payment charges associated with these accounts. The borderline revenues are not included in the calculation of the LPC:SC revenue ratio because these revenues are deemed to be fully collectible by the Company. The historic test year revenues compared to the 2011 forecast revenues shown on Attachment A, increased by 7.47%, at the same rate as LPC's increased. The forecast LPCs for rate years 2012 and 2013 increased by 1.2% and 1.75%, respectively, at the same rate as revenues increased, as shown on Attachment A.

Name of Respondent:	Date of Reply:
Pamela B. Dise	March 22, 2010

Form 103

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Historical Test Year Ending September 30, 2009 and Rate Year Ending 12/31/11, 2012, 2013
Miscellaneous Revenue - Late Payment Charges
($000's)

Line	Late Payment Charges	Source Ref.	Test Year Ending Sep 30, 2009	Normalized Adjustments	Rate Year Ending 2011	Normalized Adjustments	Rate Year Ending 2012	Normalized Adjustments	Rate Year Ending 2013
1	Total Electric Retail Revenue (excl Disp Station Svc)		$ 2,834,349.1	$ 211,713.6	$ 3,046,062.7	$ 34,155.6	$ 3,080,218.3	$ 53,789.1	$ 3,134,007.4
2	ESCO Electric Commodity Revenue		$ 287,904.5	$ (287,904.5)	$ -	$ -	$ -	$ -	$ -
3	Total		$ 3,122,253.7	$ (76,190.9)	$ 3,046,062.7	$ 34,155.6	$ 3,080,218.3	$ 53,789.1	$ 3,134,007.4
4	Late Payment Charges (Less Disp Station Svc)		$ 14,943.8	$ (364.7)	$ 14,579.2	$ 163.5	$ 14,742.6	$ 257.4	$ 15,000.1
5	LPC adjustments disputed Station Svc		$ 149.2	$ (149.2)	$ -	$ -	$ -	$ -	$ -
6	Total		**$ 15,093.1**	**$ (513.9)**	**$ 14,579.2**	**$ 163.5**	**$ 14,742.6**	**$ 257.4**	**$ 15,000.1**
7	LPC as a % of retail revenues (including ESCO Commodity)		0.4786%		0.4786%		0.4786%		0.4786%
8	Total Electric Retail Revenue (excl Disp Station Svc)		$ 2,834,349		$ 3,046,063		$ 3,080,218		$ 3,134,007
9	LPC re: Electr Retail Revenues		$ 13,566		$ 14,579		$ 14,743		$ 15,000
10	% Difference in Revenues				7.47%		1.12%		1.75%
11	% Difference in LPC's				7.47%		1.12%		1.75%

Abridged

Date of Request: March 11, 2010
Due Date: March 22, 2010

Request No. CVB-8
NMPC Req. No. NM 223 DPS 134

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christian Bonvin

TO: Infrastructure and Operations Panel

Request:

1. For each inspection code contained in the tables in Exhibit__IOP-14, Schedule 1, pages 308 through 315, please indicate whether the repair is typically capitalized or expensed.
2. Please explain how the information provided in response to the previous question supports the following statements made in the Infrastructure Panel Testimony:

- Level II deficiencies, which must be addressed within 12 months of identification, are expected to lead to remediation efforts which will be more evenly balanced between expense activities and capital expenditures (page 213 line 20).
- Typically, Level III-type of situations would be less likely to be addressed though maintenance activities, and instead more likely to be remedied through capital expenditures (page 214 line 8).

3. Please provide the actual O&M expenses incurred for repairs made in response to the inspection findings listed the tables in Exhibit__IOP-14, Schedule 1, pages 308 through 315, and the number of findings addressed. The expenses and number of repairs should be separated for level I, level II and level III activities.

4. Please provide the workpapers for how the Company determined the forecasted incremental expense levels indicated in Exhibit IOP-8, Schedule 1.

Response:

1) See attachment 1 (CVB-8_Attach 1_Inspection Code Expense Type) for a listing of the maintenance codes and the default capital or expense charge type.

2) The majority of Level II items found typically have 1 year time frame to perform the maintenance, whereas level III items have a 3 year time frame. Most of the larger capital items such as pole or transformer replacements are captured as a Level 3. The inspection

system is designed such that when replacing a pole all the expense items captured at that pole location will automatically be closed out when the pole is replaced.. For example in Exhibit__(IOP-14) Schedule 1, Sheet 310 of 315 in the overhead distribution table we have collected 909 poles to be replaced as Level 2 and 3,990 as Level 3. This example supports the statement that Level 3 derives more capital work when compared to level 2, which results in a higher percentages of level 3 expenses being capitalized.

3) The actual O&M expenses incurred for repairs made in response to the inspection findings listed on the tables in Exhibit__IOP-14 Schedule 1 are shown in the table below. Please refer to attachment 2 (CVB-8_Attach 2_completed repair to date for items in Exhibit IOP_14) for the number of repairs completed. The O&M cost corresponds to all Level II and Level III repairs completed as of 03/14/2010 for all the inspection findings between 12/01/2008 – 08/10/2009. Please note that some of Level III work automatically rolls into a Level II if both priorities are at the same locations except for street light bonding code, which will impact the actual cost Level II repairs. Level I repairs are carried out under Damage/Failure blanket projects and are not tracked or budgeted separately.

	Priority	Actual Operating Expenses
Distribution OH	Level 2	$1,060,026
	Level 3	$1,344,491
Distribution OH IM Total		**$2,404,517**
Underground	Level 2	$179,408
Underground IM Total		**$179,408**
Sub-Transmission	Level 2	$3,285
Sub-Transmission IM Total		**$3,285**
Grand Total		**$2,587,210**

4) Please refer to attachment 3 (CVB-8_Attach 3_NY Expense Estimates Work Paper) for the forecasted incremental expense levels provided in Exhibit__(IOP-8), Schedule 1. The strategy estimate plan was developed in 2009 with the Level III scheduled as shown in table1 in Attachment 3. As part of a recent budget revaluation, the Level III work plan schedules have changed based on actual costs, work plan and forecast, which was submitted in data request NM 183 DPS 113 RAV-46 for austerity measures.

Name of Respondent:
John Gavin

Date of Reply:
March 21, 2010

Note: Some codes such as damaged handholes will be assigned to the local design group for evaluation and an expense or capital order can be created at that time.

code	Description	Exp/Cap
98	Street Light Hazard Condition	E
99	Street Light - Not Bonded	E
100	Street Light - Not Bonded to Standards	E
101	Pole - Osmose Priority	C
102	Pole - Osmose Reject	C
103	Pole - Down Ground & Rod Present	E
106	Pole - Double Wood - NG transfer req'd	C
107	Pole - Double Wood - Tel transfer req'd	C
108	Pole - Double Wood - CATV transfer req'd	E
110	Pole - Broken / Severely damaged	C
111	Pole - Visual rotting ground line	C
113	Pole - Cu Nap Treated Birth Mark Yr	C
114	Pole-Woodpecker Holes	C
115	Pole - Riser guard required	E
116	Pole - Visual rotting pole top	C
117	Pole - Leaning pole	E
118	Pole - Stencil / Correction Reqd	E
119	Pole - Birds nest (Osprey)	E
120	Crossarm - Damage arm	E
121	Crossarm - Loose/defective pins	E
122	Crossarm - Wooden pins 13.2 kv	E
123	Crossarm - Loose brace, hardware	E
124	Crossarm - Damage double crossarm	E
125	Crossarm - Damage alley arm	E
126	Crossarm - Wood Brace Required/BIL	E
127	Primary on Crossarm	E
130	Insulator - Broken/Cracked/Flashed	E
131	Insulator - Floating	E
132	Insulator-I-7 aluminum caps	E
133	Insulator - non standard for voltage	E
134	Insulator - AL cap assoc with switch/fus	E
135	Insulator - Covered Wire on Porcelain	E
139	Insulator - Other (use comments)	E
140	Primary - Insuff. grnd clearance	E
141	Primary - Dmgd. cond/brkn strands	E
142	Primary - Limbs on Primary	E
145	Primary - Damaged stirrups/Connector	E
146	Primary - Improper Sag	E
147	Primary - L.A. Missing Transition	E
148	Primary - L.A. Missing End of Line	E
149	Primary-LA Blown	E
150	Transformer - Oil weeping	C
151	Transformer - Bushings brkn/cracked	C
152	Transformer - Missing ground wire	E
153	Transformer - LA blown/missing/improper	E

155	Transformer - Animal guards required	E
156	Transformer - NonStd Installation of Gap	E
157	Transformer - Improper/missing Bond	E
160	Capacitor - Oil weeping	C
161	Capacitor - Bulging	C
162	Capacitor - Bushings brkn/cracked	C
163	Capacitor - Missing ground wire	E
164	Capacitor - Blown fuse	E
165	Capacitor - Improper/missing Bond	E
166	Capacitor - Animal Guard Missing	E
167	Capacitor - L.A.blown/missing/improper	E
168	Capacitor - Control Cab Height/ground	E
169	Capacitor - Out of Service	E
170	Regulator - Oil weeping	C
171	Regulator - Bushings brkn/cracked	C
172	Regulator - Missing ground wire	E
174	Regulator Control Cab. height/ground	E
175	Regulator - Improper/missing Bond	E
176	Regulator - Animal Guard Missing	E
177	Regulator - L.A. blown/missing/improper	E
180	Sectionalizer - oil weeping	C
181	Sectionalizer - Bushings brkn or crack	C
182	Sectionalizer - Missing ground wire	E
183	Sectionalizer - Control Cab Height/Grnd	E
184	Sectionalizer - Improper/missing bond	E
185	Sectionalizer - Animal Guard Missing	E
186	Sectionalizer - LA blown/miss/improper	E
190	Recloser - Oil weeping	C
191	Recloser - Bushings brkn or crack	C
192	Recloser - Missing ground wire	E
193	Recloser - Control Cab Height/Ground	E
194	Recloser - Improper/missing bond	E
195	Recloser - Animal Guard Missing	E
196	Recloser - L.A. blown/missing/improper	E
203	Switch - Gang Operated defective	C
204	Switch - Single phase defective	C
205	Switch - Improper/missing bond	E
207	Switch - L.A. blown/missing/improper	E
208	Switch - Handle Not Bonded	E
210	Ground - Ground wire broken/loose	E
211	Ground - Hazard condition	E
212	Ground - Guard Req'd	E
213	Ground - non standard	E
214	Ground - Not Bonded to Neutral	E
220	Guy - Guy Wire marker	E
221	Guy - Guy Insulator Required	E
222	Guy - Excessive slack in guy	E
223	Guy - Broken guy wire	E
225	Guy - non standard bonding or insulation	E
226	Anchor req'd - joint owned	E
227	Anchor req'd - sole NG	E
231	Secondary - limb on secondary	E

232	Secondary - Improper sag	E
234	Secondary - Floating	E
240	Service - Ins. loose from house	E
241	Service - limb on service	E
243	Service - non std or unsecured NG action	E
250	ROW - Brush/Tree/Washout	E
260	GIS map doesn't match field	E
261	GIS Pole/line numbering in error on GIS	E
262	GIS Equipment/hardware missing in GIS	E
263	GIS Equip removed in fld, remv from GIS	E
269	GIS Other GPS/GIS errors	E
270	Spacer Cable - Damaged/Missing spacer	E
271	Spacer Cable - Bracket Damage	E
272	Spacer Cable - Bracket not bonded	E
273	Spacer Cable - Messenger not bonded	E
274	Spacer Cable - Messenger Guard Missing	E
276	Spacer Cable - Uncovered Splice	E
280	Cutout - Defective cutout	E
281	Cutout - Potted Porcelain	E
282	Cutout - Banded Porcelain	E
283	Cutout - Enclosed	E
284	Cutout - Non Porcelain	E
285	Cutout-Potted Hybrid	E
286	Spur Tap - Not Fused	E
289	Cutout - Other - Use Comments	E
290	Riser - Improper cable support/terminate	E
291	Riser - Improper/missing bond	E
292	Riser - Animal Guard Missing	E
293	Riser - L.A. blown/missing/improper	E
400	Infrared- Problem-Switch	E
401	Infrared- Problem-Cutout	E
402	Infrared-Problem- Splice	E
403	Infrared-Problem- Other	E
600	Handholes - Broken/damaged/unsecured	C
602	Handholes - Missing nomenclature	E
603	Handholes - Secondary needs repair	E
604	Handholes - Other (use comments)	E
651	Switchgear - Barrier broken/damaged/unse	C
652	Switchgear - Base broken/damaged	C
654	Switchgear - Cable Not Bonded	E
656	Switchgear - Door Broken/Damaged	E
657	Switchgear - excessive vegetation	E
659	Switchgear - Missing ground	E
660	Switchgear - Missing Nomenclature	E
661	Switchgear - Other	E
662	Switchgear - Rusted/Paint peeling	E
673	PM Transf - Door Broken/damaged/unsecu	E
675	PM Transf - Elbows/Terminator tracking/burn	E
676	PM Transf - Excessive Vegetation	E
680	PM Transf - Missing Ground	E
681	PM Transf - Missing Nomenclature	E
682	PM Transf - Mud/Debris	E

684	PM Transf - Oil Weeping	C
685	PM Transf - Pad broken/damaged	E
686	PM Transf - Protection (ballards) dama	E
687	PM Transf - Rusted/ Paint peeling	E
688	PM Transf - Pad Pushed off Base	E
740	Enclosures - Base Broken/Cracked	C
741	Enclosures - Door Broken/damaged/unsec	E
742	Enclosures - Elbows Tracking/Burned	E
743	Enclosures - Excessive Vegetation	E
745	Enclosures - Missing Nomenclature	E
746	Enclosures - Rusted/Paint Peeling	E
801	Osmose - Identified Priority Pole	C
802	Osmose - Identified Reject Pole	C
803	Osmose - Excessive Chkg (NR) offrd	N/A
804	Osmose - Climbing Insp Req'd(not reject)	N/A
	Total	

code	Description	Exp/Cap
260	GIS map doesn't match field	E
261	GIS Pole/line numbering in error on GIS	E
262	GIS Equipment/hardware missing in GIS	E
263	GIS Equip removed in fld, remv from GIS	E
269	GIS Other GPS/GIS errors	E
600	Handholes - Broken/damaged/unsecured	C
602	Handholes - Missing nomenclature	E
603	Handholes - Secondary needs repair	E
604	Handholes - Other (use comments)	E
610	Manhole - Ground Rods Missing	E
611	Manholes - Cable/Joint leaking	E
612	Manholes - Cables bonded/Grid defective	E
614	Manholes - Cracked/broken	C
615	Manholes - Fire proofing	E
616	Manholes - Improper grade	E
617	Manholes - Missing nomenclature	E
620	Manholes - Rerack	E
621	Manholes - Ring/cover repair/replace	E
622	Manholes - Roof Condition - Use Comments	C
623	Manholes - Chimney Condition - Comments	C
624	Manholes - Manhole Needs Cleaning	E
625	Manhole - Secondary Needs Repair	E
626	Manholes - No Holes in Manhole Cover	E
630	Network Protector - Barriers broken/dama	C
632	Network Protector - Oil leak	E
633	Network Protector - Worn/damaged gasket	C
635	Network transformer - Bushing Broken/Cra	C
637	Network transformer - Low oil	E
638	Network transformer - Missing Ground	E
639	Network transformer - Missing nomenclatu	E
642	Network transformer - Oil Weeping	C
643	Network transformer - Rusted/ Paint peel	E
651	Switchgear - Barrier broken/damaged/unse	C
652	Switchgear - Base broken/damaged	C
654	Switchgear - Cable Not Bonded	E
656	Switchgear - Door Broken/Damaged	E
657	Switchgear - excessive vegetation	E
659	Switchgear - Missing ground	E
660	Switchgear - Missing Nomenclature	E
661	Switchgear - Other	E
662	Switchgear - Rusted/Paint peeling	E
672	Transformer - Bushing Broken/Cracked	C
673	Transformer - Door Broken/damaged/unsecu	E
675	Transformer - Elbows/Terminator tracking/burned	E
676	Transformer - Excessive Vegetation	E
680	Transformer - Missing Ground	E
681	Transformer - Missing nomenclature	E
682	Transformer - mud/debris	E
684	Transformer - Oil Weeping	C
685	Transformer - Pad broken/damaged	C
686	Transformer - Protection (ballards) dama	C

687	Transformer - Rusted/ Paint peeling	E
690	Trench - Exposed Cable	E
692	Trench Path - Sunken	E
700	Vaults - Cable missing bond	E
702	Vaults - Cracked/broken	C
703	Vaults - Damaged/broken cover	E
704	Vaults - Damaged/broken door	E
705	Vaults - Damaged/broken ladder	E
706	Vaults - Improper grade	E
707	Vaults - Improper nomenclature	E
708	Vaults - Light not working	E
712	Vaults - Sump pump broken	C
713	Vault - Secondary Needs Repair	E
720	Submersible equip. - Excess corrosion	C
721	Submersible equip. - Physical damage	C
722	Submersible equip. - Leaking	C
730	Anodes - Missing	E
731	Anodes - Need replacement	E
	Unknown	E
	Total	

code	Description	Exp/Cap
510	POLE - Broken	C
511	POLE - Visual Rotting	C
512	POLE - Leaning	E
513	POLE - Replace Single Arms	C
514	POLE - Replace Double Arms	C
515	POLE - Repair Braces	E
516	POLE - Replace Braces	E
517	POLE - Replace Anchor	E
518	POLE - Install Anchor	C
519	POLE - Repair/Replace Guy Wire	E
521	POLE - Tighten Guy Wire	E
522	POLE - Replace/Install Guy Shield	E
524	POLE - Guy Not Bonded	E
525	POLE - Lightning Damage	C
526	POLE - Woodpecker Damage	E
527	POLE - Insects	E
528	POLE - Aerial Number Missing	E
531	TOWER - Tower Legs Broken	E
532	TOWER - Numbers Missing	E
534	TOWER - Loose Bolts/Hard	E
535	TOWER - Repair Anti-Climb	E
536	TOWER - Vegetation on Tower	E
537	TOWER - Structure Damage	E
538	TOWER - Straighten Tower	E
539	TOWER - Arms Damaged	E
541	CONDUCTOR - Conductor	E
542	CONDUCTOR - Static	E
543	CONDUCTOR - Ground Wire	E
544	CONDUCTOR - Sleeve/Conn	E
546	CONDUCTORS - Under 25 ft	E
547	Infrared Problem Identified	E
551	LINE HDW - Insulators/Dam	C
552	LINE HDW - Insulator Plumb	E
553	LINE HDW - Hardware Dam	E
555	LINE HDW - Lightning Arrestor	C
563	FOUNDATION - Erosion	E
571	RIGHT OF WAY - Erosion	E
572	RIGHT OF WAY - Encroachments	E
573	RIGHT OF WAY - Debris	E
574	RIGHT OF WAY - Danger Tree	E
575	RIGHT OF WAY - Gate Broke	E
576	RIGHT OF WAY - Oil/Gas Leak	E
581	MISC - Stencil Structure	E
582	MISC - Switch Damaged	E
583	MISC - Damaged Switch Ground	E
584	MISC - Install Warning Sign	E
585	MISC - Replace Signs	E
586	MISC - Remove Steps	E
587	MISC - Add Dirt and Tamp	E
760	GIS map doesn't match field	E
761	GIS Equipment stenciling in error on GIS	E

762	GIS Equipment/hardware missing in GIS	E	
763	GIS Equip removed in fld, remv from GIS	E	
769	GIS Other GPS/GIS errors	E	
901	Osmose - Identified priority pole	C	
902	Osmose - Identified reject pole	C	
903	Osmose - Insp excessive check (not rej)	C	
904	Osmose - Climbing Insp re'q (not rej)	C	
	Totals		

Date of Request: March 11, 2010
Due Date: March 22, 2010

Request No. RAV-57
NMPC Req. No. NM 224 DPS 135

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Robert Visalli

TO: Rate Design, Customer and Markets Panel

Request:

In response to IR RAV-40, Part B, a schedule showing the baseline number of employees assumed as the starting point for measuring KeySpan merger savings, was provided, as was a schedule for the savings initiative in place at the start of the Narragansett Gas merger. For each schedule, provide the exact date these attached schedules were produced. Include supporting documentation for the exact date (e.g., internal e-mail correspondence sending the schedules to senior management, etc).

Response

In response to RAV-40, a schedule was provided representing that the baseline number of employees assumed as the starting point for the Keyspan merger initiatives was 17,763. In addition, a second schedule was provided to show that the actual level of employees at the merger date was 17,760, demonstrating that the Narragansett initiatives had been realized. Both of these schedules were derived from a larger excel file created on September 24, 2007 which is create date/time-stamped on the file. Not included in the Company's initial response is a word document which details how the baseline number was derived. This file has a create date/time stamp of October 26, 2008 and was attached to an internal e-mail of the same date.

Also included in our initial response to RAV-40 was a schedule of savings initiatives. This data was taken from an excel file with a create date/time stamp of January 16, 2004. Although this date is more than two years prior to the Narragansett Gas merger, the Company believes that this was an original Mercer consulting template created by Mercer in 2004 and then used for the Narragansett Merger purpose at a later date. This file has a create date/time stamp of April 1, 2007. There is also a print date time/stamp on the file of October 31, 2006. It is the Company's belief that these later dates are indicative of work specific to the Narragansett Gas merger.

Name of Respondent:
James Molloy

Date of Reply:
March 20, 2010

Form 103

Date of Request: March 12, 2010
Due Date: March 22, 2010

Request No. DAG-4
NMPC Req. No. NM 227 DPS 138

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request: Expense Type #400 – Other Expenses
1. In the workpapers for Other Expenses (Book 16 of Exhibit __ (RRP-10)), pages #10-37 show a listing of costs by project for the HYE 9/30/09. The label at the top of page states, "Other Expense Type 400, General Ledger Review by Project."

a. Please explain in detail what this project and cost listing is supposed to represent, and if all the costs for the HYE 9/30/09 that are identified by the "difference" column are contained as part of the total Expense type #400 costs per book for the HYE 9/30/09 of ($8,199,600) – electric allocation is ($15,025,400); gas allocation is ($6,825,800). If the costs in their entirety are not part of Expense type #400, please provide details as to what expense types (and/or construction accounts) the projects relate to and associated amounts.

b. Workpaper pages #10-37 contains almost 2,000 listed projects. Please provide both a detailed explanation of the process the Company undertook, as well as any and all analyses done, to determine what projects and the associated costs should either be removed or left in the historic test year base, and what normalizing adjustments were required from the historic test year to the rate years.

c. Referencing workpaper pages #10-37, please provide the following:
(1) Explain and provide details on Project #X00078 – Misc Project Support;
(2) Explicitly identify the adjustments made in the rate case filing to remove historic year charges for Project #X05684 – KeySpan Integration in the amount of $21,203,514;
(3) Explicitly identify the adjustments made in the rate case filing to remove historic year charges for Project #E00802 – SIR Program costs in the amount of $19,160,251;
(4) Explicitly identify the adjustments made in the rate case filing to remove historic year charges for Project #X09545 – NM Management Audit 2008 in the amount of $2,986,573;
(5) Explicitly identify the adjustments made in the rate case filing to remove historic year charges for Project #X10407 – Global ERP Write-off in the amount of $2,636,042;

(6) (a) Explain and provide details on Project #X06704 – Transformation; (b) explicitly identify where in the workpapers, the historic year charges of $9,154,185 can be found; and (c) why the costs for this should not considered costs to achieve;
(7) (a) Explain and provide details on Project #X08686 – INVP 1242; (b) explicitly identify where in the workpapers, the historic year charges of $1,141,864 can be found; and (c) why the costs for this should not considered costs to achieve, but instead should remain in the historic test year base;
(8) (a) Explain and provide details on Project #X09966 – INVP 1185 - DMS; (b) explicitly identify where in the workpapers, the historic year charges of $626,152 can be found; and (c) why the costs for this should remain in the historic test year base;
(9) (a) Explicitly identify the adjustments made in the rate case filing to remove historic year charges for Project #X07264 –Non CTA Exceptional in the amount of $258,799
10; (b) Explain and provide details on Project #X02771 – CSS Consolidation Project; (c) explicitly identify where in the workpapers, the historic year charges of $117,297 can be found and (d) why the costs for should remain in the historic test year base;
11 (a) Explain and provide details on Project #X09465 – US T Global Transformation Project; (b) explicitly identify where in the workpapers, the historic year charges of $98,507 can be found; and (c) why the costs for should remain in the historic test year base.

Response:

1.a. The listing at Exhibit__(RRP-10), Schedule X, Sheets 10-37 represents the twelve months ended September 30, 2008 and the twelve months ended September 30, 2009 NMPC Electric departmental operating expenses, by PeopleSoft project number and description, for all expense types. The third column "Difference" represents the delta between the two periods. Please note the total of column "Total Sept 09" agrees to the total historical test year Electric departmental operating expenses shown at Exhibit___(RRP-2), Summary, Sheet 1. These costs represent all expense types. Please refer to Exhibit___(RRP-2), Summary, Sheet 1 for a breakdown of column "Total Sept 09" by expense type.

b. Project descriptions were scrutinized for terms which may be neither NMPC nor Electric business related. For example, projects containing phrases such as KeySpan, MA, RI, or Gas were flagged to be removed from the Historical test year. The Company also investigated large or unexpected variances year over year.

c. Please note, the amounts referenced in the above request at part (c) refer to the "Difference" column at Book 16, Exhibit__ (RRP-10), pages #10-37. Amounts reflected in the historical test year would be those shown in column "Total Sept 09", and therefore the Company refers to the test year amounts in its response to part (c) below.

(1) Project #X0078 Misc Project Support: This project relates to SBC, RPS and Energy Efficiency activities and the internal labor and overheads associated with those activities. Please refer to Attachment C1 for detail and workpaper references.

(2) Project #X05684 – KeySpan Integration: Of the project total ($14,115,741), $12,220,998 was excluded from the historical test year as cost to achieve. The remaining $1,894,742 relates to non-VERO related internal labor and overhead costs incurred to deliver merger initiatives. Please refer to Attachment C2 for detail and workpaper references which identify adjustments made in the filing to remove these projects costs from the historical test year.

(3) Project #E00802 – SIR Program: SIR program costs were not removed from the Historical test year. Of the project total ($37,484,707), $36,825,249 is included as SIR costs at Exhibit__(RRP-2), Schedule 40, Sheet 1, net of deferrals recorded to a blank project. Please refer to the detailed listing of project costs at Attachment C3. The remaining project amount of $659,457 consists mainly of non-incremental labor & benefits charges related to SIR programs.

(4) Project #X09545 – NM Management Audit 2008: $667,001 was removed from the historical test year expense, under expense type 400, at Exhibit__(RRP-2), Schedule 7, Sheet 4, Line "To remove one time costs related to the Management Audit". $667,001 represents amounts expensed for NorthStar Consulting Group, who conducted the audit. Because the Company would not have incurred these costs had it not been for the Management Audit, and such an audit is not anticipated in the Rate Years, and the Company therefore removed NorthStar Consulting costs from the historical test year base. However, in responding to this request, the Company has discovered an additional $139,878 in charges from NorthStar Consulting, which were not removed from the test year. The Company will include this reduction in its Corrections & Updates filing. The remaining costs ($2,320,325) consist mainly of internal labor and benefits as well as external legal counsel expense. Those costs were considered normal and ongoing operating expenses, and therefore were not removed from the historic test year.

(5) X10407 Global ERP Writeoff $2,636,042: This amount was removed from the Historical test year at Exhibit__(RRP-2), Schedule 7, Sheet 4, Line "To remove one time costs related to the W/O of ERP System".

(6) Project #X06704 – Transformation $16,617,910: Please refer to the detailed listing of project costs at Attachment C6. $10.97M of this project relates to the EDO Transformation. A description of the EDO Transformation project is included in the Infrastructure and Operations Panel (IOP) Testimony (Book 26) beginning on Page 44. $4.8M of this project relates to the Global Procurement Transformation project. A description of this project is included in the IOP testimony at Book 26, pages 43-44. $451k relates to a Station & Protection Standards project for Substation Engineering. Costs consist of consultant & contractor expenses. The goal of this project is to update & revise procedures surrounding the Project Management process for T&D project management groups, making standards as consistent as possible across the New York and New England regions. $351K of Project X06704 relates to Shared Services Transformation, which seeks to identify opportunities to standardize processes and increase efficiencies across the US and UK Shared Services groups. Costs consist of consulting and legal expense, as well as internal labor and benefits expense. The

Company views all Transformation costs as ongoing business expense, as the Company will continue to seek more opportunities through the Rate Years to run its businesses more efficiently, in order to realize cost savings and productivity savings. Therefore, the Company believes such Transformation expenses should remain in the historical test year base.

(7) Project #X08686 – INVP 1242: This project relates to the requirements and design phase costs as well as software maintenance costs incurred with the build of the new Transformation KPI Reporting software. This software supports EDO Transformation initiatives. The Company believes these costs should remain in the historical test year as it expects to incur ongoing maintenance costs associated with the KPI Reporting system through the Rate Years. Please refer to the detailed listing of project costs at Attachment C7.

(8) Project #X09966 – INVP 1185: This project relates to the requirements and design phase costs incurred with the build of the new Distribution Management System (DMS). The Company believes these costs should remain in the historical test year as it expects to incur ongoing maintenance costs associated with the DMS system through the Rate Years. Please refer to the detailed listing of project costs at Attachment C8.

(9) Project #X07264 –Non CTA Exceptional: Costs under this project mainly relate to Transformation initiatives, such as the Call Center Improvement, Global Procurement and US Shared Services Transaction Delivery Center (TDC), as well as the Regulatory Cost Structure initiative. The Global Procurement Transformation project is described in the IOP testimony at Book 26, pages 43-44. The TDC is described in the testimony of Andrew F. Sloey at Book 5, pages 24-26. The Regulatory Cost Structure (RCS) project seeks to align regulatory and line of business views for more timely and effective reporting to both management and regulatory bodies. RCS also involves software development. The Company views all Transformation costs as ongoing business expense, as the Company will continue to seek more opportunities through the Rate Years to run its businesses more efficiently, in order to realize cost savings and productivity savings. Therefore, the Company believes such Transformation expenses should remain in the historical test year base. Likewise, the Company believes it is continuously aiming to improve its reporting mechanisms and expects it will incur ongoing maintenance costs associated with RCS software. Therefore, such RCS expenses should remain in the historical test year base. Please refer to the detailed listing of project costs at Attachment C9.

(10) Project #X02771 – CSS Consolidation: This Project consists of internal labor and benefits costs associated with maintaining the CSS system updates installed in conjunction with the NY CSS/ NE CIS consolidation project. As the related capital asset was projected to have a ten-year useful life beginning January 2008, the Company expects similar CSS operating & maintenance costs to continue into the Rate Years. Please refer to the detailed listing of project costs at Attachment C10.

(11) Project #X09465 – US T Global Transformation: This project relates to an initiative to share best practices and standardize processes across the US and UK Transmission businesses. The charges of $112,280 allocated to NiMo Electric in the test year consist mainly of internal labor and benefits costs. The Company considers initiatives such as this one to be ongoing business expense, as the Company continues to seek to run the Transmission business more efficiently. Current examples of similar initiatives include Global Transmission Asset Management Workstreams: (1) Standardization of Engineering Design; (2) Strategic Resource Management; and (3) Virtual Design Center of Excellence. The Company therefore believes these costs should remain in the historical test year base and into the Rate Year. Please refer to the detailed listing of project costs at Attachment C11.

Workpaper References:
For those expense types listed in the Attachments to Part (c), please refer to the following workpapers:

Expense Type	**Workpaper : Exhibit __(RRP-10)**
100 & 105- Consultants	Book 14, Schedule 1
110, 112 & 115 - Contractors	Book 14, Schedule 2
150 - Donations	Book 14, Schedule 3
200 – Employee expenses	Book 15, Schedule 4
300 – Hardware	Book 15, Schedule 5
350 – Software	Book 15, Schedule 6
400, 401 & 410 – Other	Book 16, Schedule 7
500, 505 & 510 – Rents	Book 16, Schedule 8
A10 through A65 – Overheads	Books 16 – 17, Schedules 9 - 17
A70 – Sales tax	Book 17, Schedule 18
B01 through B08 – Benefits	Book 17, Schedules 19-28
B09 – Payroll tax	Book 17, Schedule 27
M10 – M50 – Materials	Book 17, Schedules 28-30
P expense types – Labor	Book 18, Schedule 31
T10 – Transportation	Book 18, Schedule 32

Name of Respondent:
Melissa Little

Date of Reply:
March 23, 2009

Form 103

Project X00078
For the Historical Test Year ended September 30, 2009

Bus Unit D	Niagara Mohawk Power Corp

Sum of Posted Jrnl $						Segment	
Project	Project Descr	Rate Case Expense	Expense Type	Activity	Activity Descr	DIST	Grand Total
X00078	Misc Project Support	Acctg Services Corp Overheads	A65	AG0080	Regulatory Filing Activities	36	36
				AG0205	DSM Regulatory Related Activit	104	104
		Acctg Services Corp Overheads Total				**140**	**140**
		Benefits	B01	AG0080	Regulatory Filing Activities	109	109
				AG0195	DSM General Evaluation Work	3,047	3,047
				AG0200	DSM Planning	1,963	1,963
				AG0205	DSM Regulatory Related Activit	1,351	1,351
			B02	AG0080	Regulatory Filing Activities	4	4
				AG0195	DSM General Evaluation Work	250	250
				AG0200	DSM Planning	98	98
				AG0205	DSM Regulatory Related Activit	83	83
			B03	AG0080	Regulatory Filing Activities	72	72
				AG0195	DSM General Evaluation Work	3,277	3,277
				AG0200	DSM Planning	1,473	1,473
				AG0205	DSM Regulatory Related Activit	1,117	1,117
			B04	AG0080	Regulatory Filing Activities	11	11
				AG0195	DSM General Evaluation Work	168	168
				AG0200	DSM Planning	159	159
				AG0205	DSM Regulatory Related Activit	161	161
			B06	AG0080	Regulatory Filing Activities	51	51
				AG0195	DSM General Evaluation Work	3,837	3,837
				AG0200	DSM Planning	1,637	1,637
				AG0205	DSM Regulatory Related Activit	494	494
			B07	AG0080	Regulatory Filing Activities	21	21
				AG0195	DSM General Evaluation Work	851	851
				AG0200	DSM Planning	566	566
				AG0205	DSM Regulatory Related Activit	426	426
			B08	AG0080	Regulatory Filing Activities	(2)	(2)
				AG0195	DSM General Evaluation Work	24	24
				AG0200	DSM Planning	(2)	(2)
				AG0205	DSM Regulatory Related Activit	(21)	(21)
		Benefits Total				**21,225**	**21,225**
		Employee Expenses	200	AG0205	DSM Regulatory Related Activit	747	747
		Employee Expenses Total				**747**	**747**
		Energy Efficiency	110	AG0200	DSM Planning	3,270	3,270
			200	AG0195	DSM General Evaluation Work	351	351
				AG0200	DSM Planning	781	781
			400	AG0195	DSM General Evaluation Work	6,250	6,250
			A65	AG0195	DSM General Evaluation Work	(130)	(130)
				AG0200	DSM Planning	149	149
		Energy Efficiency Total				**10,672**	**10,672** a\
		Labor	P15	AG0080	Regulatory Filing Activities	736	736
				AG0195	DSM General Evaluation Work	24,268	24,268
				AG0200	DSM Planning	14,911	14,911
				AG0205	DSM Regulatory Related Activit	10,393	10,393
			P30	AG0080	Regulatory Filing Activities	226	226
				AG0195	DSM General Evaluation Work	2,467	2,467
				AG0200	DSM Planning	2,254	2,254
				AG0205	DSM Regulatory Related Activit	1,059	1,059
			P50	AG0080	Regulatory Filing Activities	129	129
				AG0195	DSM General Evaluation Work	4,345	4,345
				AG0200	DSM Planning	2,547	2,547
				AG0205	DSM Regulatory Related Activit	1,652	1,652
		Labor Total				**64,989**	**64,989**
		Payroll taxes	B09	AG0080	Regulatory Filing Activities	71	71
				AG0195	DSM General Evaluation Work	2,305	2,305
				AG0200	DSM Planning	1,467	1,467
				AG0205	DSM Regulatory Related Activit	998	998
		Payroll taxes Total				**4,841**	**4,841**
		System Benefits Charge	110	AG0205	DSM Regulatory Related Activit	-	-
			400	AG0205	DSM Regulatory Related Activit	36,129,739	36,129,739
				AG0207	DSM SBC NIMO	36,169,375	36,169,375
		System Benefits Charge Total				**72,299,114**	**72,299,114** b\
		Renewable Portfolio Standard	400	AG0205	DSM Regulatory Related Activit	11,999,432	11,999,432
				AG0207	DSM SBC NIMO	11,999,430	11,999,430
		Renewable Portfolio Standard Total				**23,998,862**	**23,998,862** c\
Grand Total						**96,400,590**	**96,400,590**

a\ agrees to Exhibit__(RRP-10), Schedule 33, Workpaper 2, Sheet 1
b\ agrees to Exhibit__(RRP-2), Schedule 43, Sheet 1
c\ agrees to Exhibit__(RRP-2), Schedule 39, Sheet 1

Project X05684
All charges
For the Historical Test Year ended September 30, 2009

Sum of Posted Jrnl $			Segment			CTA Adjustment	X05684
Project	Project Descr	Expense Type	DIST	TRAN	Grand Total	Per Sheet 2	Remaining
X05684	Keyspan Integration	100	(297,448)	(70,696)	(368,144)	(368,144)	(0)
		110	1,260,968	129,345	1,390,314	1,390,314	-
		150	2,208	348	2,556	2,556	-
		200	244,563	14,294	258,857	258,857	-
		300	21,680	2,970	24,650	24,650	-
		350	1,406	-	1,406	1,406	-
		400	(1,417,766)	(205,169)	(1,622,935)	(1,622,935)	-
		401	15,599	2,462	18,061	-	18,061
		410	19	3	22	-	22
		500	10,567		10,567	10,567	-
		A50	10,431		10,431	-	10,431
		A60	-	-	-	-	-
		A65	874	98	972	-	972
		A70	205	0	206	-	206
		B01	312,492	35,709	348,201	270,455	77,746
		B02	1,784	233	2,017	-	2,017
		B03	55,182	3,042	58,223	-	58,223
		B04	2,044	261	2,305	-	2,305
		B05	(0)	-	(0)	-	(0)
		B06	10,629,898	1,447,126	12,077,024	12,021,477	55,547
		B07	8,038	779	8,818	-	8,818
		B08	(155)	(19)	(174)	-	(174)
		B09	21,133	612	21,745	-	21,745
		M10	229,795	1,900	231,695	231,695	-
		M20	101		101	101	-
		M50	21		21	-	21
		P15	495,756	24,478	520,234	-	520,234
		P20	26,735		26,735	-	26,735
		P21	14,060		14,060	-	14,060
		P25	8,085	-	8,085	-	8,085
		P26	2,374	-	2,374	-	2,374
		P30	743,579	235,171	978,750	-	978,750
		P50	76,566	3,728	80,294	-	80,294
		T10	7,564	708	8,272	-	8,272
X05684 Total			**12,488,358**	**1,627,383**	**14,115,741**	**12,220,998**	**1,894,742**
Grand Total			12,488,358	1,627,383	14,115,741		

Project X05684
Keyspan and NEG Integration Costs to Achieve
For the Historical Test Year ended September 30, 2009

		Segment CAT	Project		
	Sum of Posted Jrnl $	ELECTRIC		**ELECTRIC Total**	Grand Total
Line	Expense Type	X05683	X05684		
1	100		(368,144)	**(368,144)**	**(368,144)**
2	110		1,390,314	**1,390,314**	**1,390,314**
3	150		2,556	**2,556**	**2,556**
4	200	7,747	258,857	**266,604**	**266,604**
5	300		24,650	**24,650**	**24,650**
6	350		1,406	**1,406**	**1,406**
7	400,401,410	1,436	(1,622,935)	**(1,621,499)**	**(1,621,499)**
8	500,505,510		10,567	**10,567**	**10,567**
9	B01		270,455	**270,455**	**270,455**
10	B06		12,021,477	**12,021,477**	**12,021,477**
11	M10		231,695	**231,695**	**231,695**
12	M20		101	**101**	**101**
13	**Grand Total**	**9,183**	**12,220,998**	**12,230,181**	**12,230,181**

agrees to Sheet 1

Line Notes:	Source:
1	Exhibit___(RRP-2), Schedule 1 Sheet 4
2	Exhibit___(RRP-2), Schedule 2 Sheet 4
3	Exhibit___(RRP-2), Schedule 3 Sheet 4. Booked below the line.
4	Exhibit___(RRP-2), Schedule 4 Sheet 4
5	Exhibit___(RRP-2), Schedule 5 Sheet 4
6	Exhibit___(RRP-2), Schedule 6 Sheet 4
7	Exhibit___(RRP-2), Schedule 7 Sheet 4
8	Exhibit___(RRP-2), Schedule 8 Sheet 4
9	Exhibit___(RRP-2), Schedule 19 Sheet 4
10	Exhibit___(RRP-2), Schedule 24 Sheet 4
11	Exhibit___(RRP-2), Schedule 28 Sheet 4
12	Exhibit___(RRP-2), Schedule 29 Sheet 4
13	Sum (Lines 1 - 12)

NIAGARA MOHAWK POWER CORPORATION
d/b/a National Grid
Case 10-E-0050
Attachment C3 to DAG-4
Sheet 1 of 3

Project E00802
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of GL Act $					Rate Case Segment	
Project	Project Descr	Charged Dept	Chrg Dept Descr	Expense Type	ELECTRIC	Grand Total
E00802	SIR Program Costs - NY	11999	Acctg Services Corp Overheads	A65	1,890	1,890
				P30	40,903	40,903
		11999 Total			42,793	42,793
		15550	Real Estate-NY Cent	110	478	478
				500	212	212
		15550 Total			690	690
		15890	NY Facilities-Frontier	110	5,748	5,748
				P10	1,151	1,151
				P50	204	204
		15890 Total			7,103	7,103
		15900	NY Facilities-Southwest	A70	5	5
				M10	54	54
		15900 Total			58	58
		15920	NY Facilities-Central	110	284	284
				A70	22	22
				P10	278	278
				P50	50	50
				T10	23	23
		15920 Total			658	658
		15930	NY Facilities-Northern	M10	6	6
				P10	132	132
				P50	24	24
				T10	16	16
		15930 Total			178	178
		15950	NY Facilities-Capital	M10	121	121
		15950 Total			121	121
		15960	NY Facilities-Northeast	110	585	585
				A70	41	41
				P10	1,199	1,199
				P50	205	205
				T10	218	218
		15960 Total			2,248	2,248
		16999	Human Resources Corp Overhead	B01	16,883	16,883
				B02	957	957
				B03	13,436	13,436
				B04	1,443	1,443
				B06	12,662	12,662
				B07	4,707	4,707
				B08	(118)	(118)
		16999 Total			49,969	49,969
		18000	Legal Services	100	(4,468)	(4,468)
		18000 Total			(4,468)	(4,468)
		18340	Ethics Risk & Compliance	P15	290	290
				P50	53	53
		18340 Total			343	343
		26020	Gas Construction NY	110	618	618
		26020 Total			618	618
		26050	Vegetation Management	110	2,350	2,350
		26050 Total			2,350	2,350
		38320	Site Investig & Remed Admin-NE	200	485	485
				400	173	173
				P15	15,067	15,067
				P50	2,625	2,625
		38320 Total			18,350	18,350
		38340	Site Investig & Remed Admin-NY	200	19,026	19,026
				400	481	481
				P15	154,294	154,294
				P50	25,555	25,555
		38340 Total			199,356	199,356

NIAGARA MOHAWK POWER CORPORATION
d/b/a National Grid
Case 10-E-0050
Attachment C3 to DAG-4
Sheet 2 of 3

Project E00802
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of GL Act $					Rate Case Segment		
Project	Project Descr	Charged Dept	Chrg Dept Descr	Expense Type	ELECTRIC	Grand Total	
		38360	Site Investig & Remed-NY	100	10,164,511	10,164,511	1\
				105	5,271	5,271	
				110	22,835,209	22,835,209	
				200	10,669	10,669	
				300	188	188	
				400	2,889,716	2,889,716	
				402	113,430	113,430	
				404	660,664	660,664	
				500	800	800	
				A70	530	530	
				M10	143,816	143,816	
				M20	194	194	
				M50	43	43	
				P10	1,636	1,636	
				P15	281,128	281,128	
				P50	47,427	47,427	
				T10	209	209	1\
		38360 Total			37,155,440	37,155,440	
		62330	Trans Line Serv-NY	P15	440	440	
				P50	80	80	
				T10	52	52	
		62330 Total			571	571	
		62340	Trans Line Serv Construct-NY	200	789	789	
				P10	661	661	
				P50	124	124	
				T10	139	139	
		62340 Total			1,712	1,712	
		62360	Distribution Construction-NY	110	618	618	
		62360 Total			618	618	
		83500	Travelling Operators-West	T10	113	113	
		83500 Total			113	113	
		83510	Power Delivery-Buffalo	200	84	84	
				P10	3,684	3,684	
				P20	573	573	
				P21	286	286	
				P50	737	737	
				T10	523	523	
		83510 Total			5,887	5,887	
	SIR Program Costs - NY Total				37,484,707	37,484,707	
E00802 Total					37,484,707	37,484,707	
Grand Total					**37,484,707**	**37,484,707**	

Sum 1\ = **36,825,249**

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID (COMPANY 36)
Site Investigation Remediation
SIR Charged Department - 38360

Sum of Amount Posted				Segment		
Charged Dept	Project	Project Descr	Expense Type	ELECTRIC	Grand Total	
38360			100	4,005	4,005	
			110	(1,736)	(1,736)	
			200	-	-	
			300	(0)	(0)	
			400	(26,930,825)	(26,930,825)	
			A70	49	49	
			M20	-	-	
			M50	(10)	(10)	
	Total			(26,928,516)	(26,928,516)	
	CAP036	Capital Overheads	400	28,142	28,142	
	CAP036 Total			28,142	28,142	
	E00802	SIR Program Costs - NY	100	10,164,511	10,164,511	
			105	5,271	5,271	
			110	22,835,209	22,835,209	
			200	10,669	10,669	
			300	188	188	
			400	2,889,716	2,889,716	
			402	113,430	113,430	
			404	660,664	660,664	
			500	800	800	
			A70	530	530	
			M10	143,816	143,816	
			M20	194	194	
			M50	43	43	
			T10	209	209	
	E00802 Total			**36,825,249**	**36,825,249**	a\
	F00252	Cash Reconciliations	110	1,612	1,612	
			A70	123	123	
	F00252 Total			1,736	1,736	
Grand Total				**9,926,610**	**9,926,610**	b\

a\ agrees to Sheet 2
b\ per Exhibit__(RRP-2), Schedule 40, Sheet 1

Project X06704
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of Posted Jrnl $					Rate Case Segment	
Project	Project Descr	Work Order	Work Order Descr	Expense Type	ELECTRIC	Grand Total
X06704	Transformation	9000064394	Project Management	A65	(4)	(4)
				B01	105	105
				B02	8	8
				B03	96	96
				B04	8	8
				B06	128	128
				B07	28	28
				B08	1	1
				P15	798	798
				P30	109	109
				P50	144	144
		9000064394 Total			**1,420**	**1,420**
		9000064395	Station & Protection Standards	100	324,670	324,670
				110	127,113	127,113
		9000064395 Total			**451,783**	**451,783**
		9000076168	EDO Transformation-Phase 1 Ana	100	5,606,827	5,606,827
				110	690,481	690,481
				200	441,586	441,586
				300	4,205	4,205
				400	15,154	15,154
				A60	0	0
				A65	23,806	23,806
				A70	253	253
				B01	314,269	314,269
				B02	14,561	14,561
				B03	203,656	203,656
				B04	22,838	22,838
				B06	184,959	184,959
				B07	68,178	68,178
				B08	4,500	4,500
				M10	60,734	60,734
				P10	94,738	94,738
				P15	2,192,400	2,192,400
				P20	9,573	9,573
				P21	5,271	5,271
				P25	7,546	7,546
				P26	3,279	3,279
				P30	587,295	587,295
				P50	388,771	388,771
				T10	26,997	26,997
		9000076168 Total			**10,971,876**	**10,971,876**
		9000082161	Global Procurement Transformat	100	247,504	247,504
				110	3,249,765	3,249,765
				200	41,315	41,315
				300	1,102	1,102
				400	1,066,754	1,066,754
				A60	-	-
				A65	2,436	2,436
				A70	48	48
				B01	19,583	19,583
				B02	859	859
				B03	12,979	12,979
				B04	1,595	1,595
				B06	13,322	13,322
				B07	4,981	4,981
				B08	(140)	(140)
				M10	258	258
				P15	135,277	135,277
				P30	21,857	21,857
				P50	22,719	22,719
		9000082161 Total			**4,842,215**	**4,842,215**
		9000084515	Global Shared Services-BPO	100	321,888	321,888
				200	28,728	28,728
		9000084515 Total			**350,616**	**350,616**
X06704 Total					**16,617,910**	**16,617,910**
Grand Total					16,617,910	16,617,910

NIAGARA MOHAWK POWER CORPORATION
d/b/a National Grid
Case 10-E-0050
Attachment C7 to DAG-4
Sheet 1 of 1

Project X08686
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of Posted Jrnl $					Rate Case Segment	
Project	Project Descr	Expense Type	Charged Dept	Chrg Dept Descr	ELECTRIC	Grand Total
X08686	INVP 1242	100	17109	IS Elec Dist & Gen Projects	-	-
		100 Total			-	-
		110	17103	Inspection Maint Mgmt Systems	(3,334)	(3,334)
			17109	IS Elec Dist & Gen Projects	649,697	649,697
			17190	IS Customer & Markets-NM	1,842	1,842
		110 Total			**648,204**	**648,204**
		200	17109	IS Elec Dist & Gen Projects	6,139	6,139
			17190	IS Customer & Markets-NM	389	389
		200 Total			**6,528**	**6,528**
		300	17109	IS Elec Dist & Gen Projects	1,226	1,226
		300 Total			**1,226**	**1,226**
		350	17109	IS Elec Dist & Gen Projects	235,216	235,216
		350 Total			**235,216**	**235,216**
		A60	11999	Acctg Services Corp Overheads	-	-
		A60 Total			-	-
		A65	11999	Acctg Services Corp Overheads	2,635	2,635
		A65 Total			**2,635**	**2,635**
		A70	17109	IS Elec Dist & Gen Projects	148	148
		A70 Total			**148**	**148**
		B01	16999	Human Resources Corp Overheads	24,263	24,263
		B01 Total			**24,263**	**24,263**
		B02	16999	Human Resources Corp Overheads	1,288	1,288
		B02 Total			**1,288**	**1,288**
		B03	16999	Human Resources Corp Overheads	17,976	17,976
		B03 Total			**17,976**	**17,976**
		B04	16999	Human Resources Corp Overheads	2,133	2,133
		B04 Total			**2,133**	**2,133**
		B06	16999	Human Resources Corp Overheads	15,961	15,961
		B06 Total			**15,961**	**15,961**
		B07	16999	Human Resources Corp Overheads	6,285	6,285
		B07 Total			**6,285**	**6,285**
		B08	16999	Human Resources Corp Overheads	(74)	(74)
		B08 Total			**(74)**	**(74)**
		P10	17109	IS Elec Dist & Gen Projects	3,194	3,194
		P10 Total			**3,194**	**3,194**
		P15	17109	IS Elec Dist & Gen Projects	168,925	168,925
		P15 Total			**168,925**	**168,925**
		P30	11999	Acctg Services Corp Overheads	26,347	26,347
		P30 Total			**26,347**	**26,347**
		P50	17109	IS Elec Dist & Gen Projects	28,732	28,732
		P50 Total			**28,732**	**28,732**
X08686 Total					**1,188,987**	**1,188,987**
Grand Total					1,188,987	1,188,987

Project X09966
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of Posted Jrnl $					Segment	
Project	Project Descr	Expense Type	Charged Dept	Chrg Dept Descr	DIST	Grand Total
X09966	INVP 1185 - DMS	100	17109	IS Elec Dist & Gen Projects	239,602	239,602
		100 Total			**239,602**	**239,602**
		200	17109	IS Elec Dist & Gen Projects	33,648	33,648
			17110	Customer Applications	280	280
			38050	Dist Disp Center Wbro Ctrl	489	489
			87300	Regional Control-West	1,341	1,341
		200 Total			**35,759**	**35,759**
		300	17109	IS Elec Dist & Gen Projects	138	138
			38050	Dist Disp Center Wbro Ctrl	39	39
		300 Total			**177**	**177**
		350	17109	IS Elec Dist & Gen Projects	305	305
		350 Total			**305**	**305**
		A60	11999	Acctg Services Corp Overheads	-	-
		A60 Total			-	-
		A65	11999	Acctg Services Corp Overheads	2,275	2,275
		A65 Total			**2,275**	**2,275**
		B01	16999	Human Resources Corp Overheads	35,804	35,804
		B01 Total			**35,804**	**35,804**
		B02	16999	Human Resources Corp Overheads	1,618	1,618
		B02 Total			**1,618**	**1,618**
		B03	16999	Human Resources Corp Overheads	19,925	19,925
		B03 Total			**19,925**	**19,925**
		B04	16999	Human Resources Corp Overheads	2,227	2,227
		B04 Total			**2,227**	**2,227**
		B06	16999	Human Resources Corp Overheads	21,876	21,876
		B06 Total			**21,876**	**21,876**
		B07	16999	Human Resources Corp Overheads	6,724	6,724
		B07 Total			**6,724**	**6,724**
		B08	16999	Human Resources Corp Overheads	172	172
		B08 Total			**172**	**172**
		M10	17109	IS Elec Dist & Gen Projects	723	723
		M10 Total			**723**	**723**
		P15	17109	IS Elec Dist & Gen Projects	169,196	169,196
			87000	Dispatch & Control Mgmt-NY	23,839	23,839
			87300	Regional Control-West	3,274	3,274
		P15 Total			**196,309**	**196,309**
		P30	11999	Acctg Services Corp Overheads	29,142	29,142
		P30 Total			**29,142**	**29,142**
		P50	17109	IS Elec Dist & Gen Projects	28,757	28,757
			87000	Dispatch & Control Mgmt-NY	4,081	4,081
			87300	Regional Control-West	452	452
		P50 Total			**33,289**	**33,289**
		T10	17109	IS Elec Dist & Gen Projects	226	226
		T10 Total			**226**	**226**
X09966 Total					**626,152**	**626,152**
Grand Total					626,152	626,152

NIAGARA MOHAWK POWER CORPORATION
d/b/a National Grid
Case 10-E-0050
Attachment C9 to DAG-4
Sheet 1 of 1

Project X07264
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of Posted Jrnl $					Segment		
Project	Project Descr	Work Order	Work Order Descr	Expense Type	DIST	TRAN	Grand Total
X07264	Non CTA Exceptional	9000067940	KeySpan integration costs--Non	100	41,489	5,629	47,118
				P30	26,321	3,602	29,923
			KeySpan integration costs--Non Total		**67,810**	**9,231**	**77,041**
		9000067940 Total			67,810	9,231	77,041
		9000088118	Customer Transformation-Call C	100	195,030		195,030
				110	61,022		61,022
				200	1,819		1,819
			Customer Transformation-Call C Total		**257,870**		**257,870**
		9000088118 Total			257,870		257,870
		9000089267	Global Procurement Transformat	200	356	56	412
				400	497	78	575
				B01	2,827	446	3,273
				B03	2,828	446	3,275
				B05	0	0	0
				B06	6,063	957	7,020
				B07	653	103	756
				B09	1,807	285	2,092
				P15	20,003	3,157	23,160
				P30	3,274	517	3,791
				P50	3,171	500	3,671
			Global Procurement Transformat Total		**41,478**	**6,546**	**48,024**
		9000089267 Total			41,478	6,546	48,024
		9000089603	US Shared Services Transactio-	200	260	35	294
				A60	-	-	-
				A65	(1,379)	(197)	(1,576)
				B01	14,001	1,787	15,787
				B02	956	123	1,079
				B03	13,245	1,710	14,955
				B04	1,058	133	1,191
				B06	14,390	1,876	16,266
				B07	3,712	471	4,183
				B08	108	14	122
				P15	129,637	14,050	143,686
				P30	10,797	1,378	12,174
				P50	22,277	2,446	24,723
			US Shared Services Transactio- Total		**209,059**	**23,824**	**232,884**
		9000089603 Total			209,059	23,824	232,884
		9000093450	Regulatory Cost Structure	100	44,876		44,876
				110	4,184	660	4,844
				200	3,368	532	3,900
				400	213	34	247
				401	208	33	241
				410	60	9	69
				510	164	26	190
				B01	2,441	385	2,826
				B03	2,769	437	3,206
				B05	-	-	-
				B06	5,578	880	6,459
				B07	535	84	620
				B09	1,549	244	1,793
				P15	17,838	2,815	20,654
				P30	10,398	1,641	12,039
				P50	2,830	447	3,276
			Regulatory Cost Structure Total		**97,011**	**8,228**	**105,238**
		9000093450 Total			97,011	8,228	105,238
X07264 Total					**673,228**	**47,829**	**721,058**
Grand Total					673,228	47,829	721,058

Project X02771
For the Historical Test Year ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of Posted Jrnl $				Rate Case Segment	
Project	Project Descr	Expense Type	Activity Descr	ELECTRIC	Grand Total
X02771	CSS Consolidation Project - Ex	200	Credit & Collections	58.09	58.09
			Miscellaneous Customer Account	2,976.83	2,976.83
		200 Total		**3,034.92**	**3,034.92**
		A60	IS Development - Customer Serv	-	-
			Operations Executive Services	-	-
		A60 Total		**-**	**-**
		A65	IS Development - Customer Serv	(0.33)	(0.33)
			Miscellaneous Customer Account	808.72	808.72
		A65 Total		**808.39**	**808.39**
		B01	IS Development - Customer Serv	15.43	15.43
			Miscellaneous Customer Account	2,056.90	2,056.90
			Operations Executive Services	5,855.70	5,855.70
		B01 Total		**7,928.03**	**7,928.03**
		B02	IS Development - Customer Serv	(0.07)	(0.07)
			Miscellaneous Customer Account	58.15	58.15
			Operations Executive Services	99.76	99.76
		B02 Total		**157.84**	**157.84**
		B03	IS Development - Customer Serv	(2.16)	(2.16)
			Miscellaneous Customer Account	998.67	998.67
			Operations Executive Services	748.19	748.19
		B03 Total		**1,744.70**	**1,744.70**
		B04	IS Development - Customer Serv	0.17	0.17
			Miscellaneous Customer Account	154.21	154.21
			Operations Executive Services	59.87	59.87
		B04 Total		**214.25**	**214.25**
		B06	IS Development - Customer Serv	2.33	2.33
			Miscellaneous Customer Account	1,083.31	1,083.31
			Operations Executive Services	2,493.89	2,493.89
		B06 Total		**3,579.53**	**3,579.53**
		B07	IS Development - Customer Serv	(0.36)	(0.36)
			Miscellaneous Customer Account	518.93	518.93
			Operations Executive Services	239.41	239.41
		B07 Total		**757.98**	**757.98**
		B08	IS Development - Customer Serv	0.11	0.11
			Miscellaneous Customer Account	(48.48)	(48.48)
			Operations Executive Services	39.92	39.92
		B08 Total		**(8.45)**	**(8.45)**
		P10	IS Development - Customer Serv	-	-
		P10 Total		**-**	**-**
		P15	Miscellaneous Customer Account	66,451.37	66,451.37
			Operations Executive Services	9,975.63	9,975.63
		P15 Total		**76,427.00**	**76,427.00**
		P30	IS Development - Customer Serv	(2.54)	(2.54)
			Miscellaneous Customer Account	8,003.17	8,003.17
			Operations Executive Services	528.61	528.61
		P30 Total		**8,529.24**	**8,529.24**
		P50	IS Development - Customer Serv	(0.22)	(0.22)
			Miscellaneous Customer Account	10,559.39	10,559.39
			Operations Executive Services	1,823.21	1,823.21
		P50 Total		**12,382.38**	**12,382.38**
		T10	Miscellaneous Customer Account	5,096.81	5,096.81
		T10 Total		**5,096.81**	**5,096.81**
X02771 Total				**120,652.62**	**120,652.62**
Grand Total				120,652.62	120,652.62

Project X09465
For the Historical Test Year Ended September 30, 2009

Bus Unit Descr	Niagara Mohawk Power Corp

Sum of Posted Jrnl $				Rate Case Segment	
Project	Project Descr	Expense Type	Chrg Dept Descr	ELECTRIC	Grand Total
X09465	US T Global Transformation	110	Construction Strategy	6,433	6,433
		110 Total		**6,433**	**6,433**
		200	Asset Management	2,696	2,696
			Construction Strategy	2,623	2,623
			System Delivery	2,302	2,302
			System Delivery Construction	909	909
			Trans Line Engineering	3,545	3,545
		200 Total		**12,074**	**12,074**
		A65	Acctg Services Corp Overheads	1,014	1,014
		A65 Total		**1,014**	**1,014**
		B01	Human Resources Corp Overheads	7,621	7,621
		B01 Total		**7,621**	**7,621**
		B02	Human Resources Corp Overheads	430	430
		B02 Total		**430**	**430**
		B03	Human Resources Corp Overheads	6,047	6,047
		B03 Total		**6,047**	**6,047**
		B04	Human Resources Corp Overheads	863	863
		B04 Total		**863**	**863**
		B06	Human Resources Corp Overheads	3,023	3,023
		B06 Total		**3,023**	**3,023**
		B07	Human Resources Corp Overheads	2,236	2,236
		B07 Total		**2,236**	**2,236**
		B08	Human Resources Corp Overheads	(127)	(127)
		B08 Total		**(127)**	**(127)**
		P15	Asset Management	2,948	2,948
			Construction Strategy	1,899	1,899
			Oper Planning & Review	2,616	2,616
			System Delivery	2,468	2,468
			Trans Line Engineering	45,798	45,798
			Trans Line Services-NE	1,183	1,183
		P15 Total		**56,910**	**56,910**
		P30	Acctg Services Corp Overheads	6,667	6,667
		P30 Total		**6,667**	**6,667**
		P50	Asset Management	486	486
			Construction Strategy	315	315
			Oper Planning & Review	416	416
			System Delivery	410	410
			Trans Line Engineering	7,266	7,266
			Trans Line Services-NE	196	196
		P50 Total		**9,088**	**9,088**
X09465 Total				**112,280**	**112,280**
Grand Total				112,280	112,280

Date of Request: March 12, 2010
Due Date: March 22, 2010

Request No. DAG-5
NMPC Req. No. NM 228 DPS 139

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request: Expense Type #400 – Other Expenses

1. Please explain and provide details, invoices, and journal entries for the historic year charge of $2,744,341 for Activity #AG0844 – IS Development A&G, as per "Other Expense Type #400" workpapers page 164.

2. Please explain and provide details, invoices, and journal entries for the historic year charge of $776,500 for Activity #AG0730 – Accounting Services, as per "Other Expense Type #400" workpapers page 68.

3. Workpaper #38 shows SIR costs by provider company and expense type. Please provide a more detailed breakdown of the SIR costs for each expense type and by activity and vendor.

Response:

1. Please see Attachment A to this request for copies of the journal entries to Activity AG0844, Expense Type 400. Most of the charges in this activity relate to the write off of the Global ERP System which has been removed from the test year (See Workpaper 5 to Exhibit __(RRP-2) Schedule 7). The remaining costs are expenses relating to the development of the enhanced Intranet.
2. Please see Attachment B to this request for the HSBC invoices. These charges are Payment and Controls Fees.
3. Please see Attachment C to this request for a breakdown of the SIR Cost.

Name of Respondent:
James Molloy

Date of Reply:
March 20, 2010

Form 103

Journal Entry

New Window | Help | Customize Page |

Header | Lines | Totals | Errors | Approval

Unit: 00099 Journal ID: 99404 Date: 03/31/2009

Long Description: Nov Mar True up: Expat Bonus and March Accrual for unbilled Expat charges

*Ledger Group: ACTUALS Auto Generate Lines

Ledger: Adjusting Entry: Non-Adjusting Entry

*Source: IMP Fiscal Year: 2009

Reference Number: Period: 12

SJE Type: ADB Date: 03/31/2009

Journal Class: Save Journal Incomplete Status

Transaction Code: GENERAL

Currency Defaults: USD / CRRNT / 1 Created: 03/31/09 3:09:27PM User ID: ppatel

Reversal: Do Not Generate Reversal Posted: Updated: 03/31/09 4:22:56PM

Save | Return to Search | Previous in List | Next in List | Notify | Refresh | Add | Update/Display

Header | Lines | Totals | Errors | Approval

ENTERED BY Prem DATE 3/31/09
POSTED BY Ca DATE 3/31/09
CHECK ACCOUNTS ✓ CHECK CALCS
COPIED PREVIOUS MO ✓
REASONABILITY ✓ VERIFY INPUTS ✓

Journal Entry

New Window | Help | Customize Page |

Header | Lines | Totals | Errors | Approval

Unit: 00099 Journal ID: 99404 Date: 03/31/2009 *Process: Edit Journal Process

Template List Search Criteria Change Values Inter/IntraUnit Errors Only Line: 110

Lines

Customize | Find |

*Unit	Activity	Project	WO	Exp Type	Orig Dept	Chrg Dept	Bill Pool	Segment	Account	Reg Acct	Amount	Journal Line Descri
00001	AG0740	X09085	9000080622	200	56900	56900		BDEV	256032	921000	17,333.01	Ahearn, B
00099	DO9140			110	25044	25044	00203	OTH	256022	586000	11,155.70	Gossage, K
00099	GO9106			110	25044	25044	00200	OTH	256022	885000	2,788.93	Gossage, K
00099	AG0993			110	92269	92269	00200	OTH	256022	901000	7,477.57	Barker, L.
00099	AG0993			110	92269	92269	00203	OTH	256022	901000	7,477.57	Barker, L.
00099	AG0760			110	86000	86000	00231	OTH	256022	921000	13,795.90	Bingham, P.
00099	AG0805			110	12100	12100	00382	OTH	256022	921000	11,800.00	Bonar, D.
00099	AG0760			110	62000	62000	00233	OTH	256022	921000	379,775.18	Brett, S.
00099	AG0483			110	15480	15480	00236	OTH	256022	921000	32,300.90	Calligher, J.
01459	AG0090			110	25250	25250		NREC	256022	921000	19,783.03	Connell, C.
01459	AG0760			110	25010	25010		NREC	256022	921000	7,338.03	Cook, M
00099	AG0760			110	25010	25010	00200	OTH	256022	921000	7,338.03	Cook, M.
00099	AG0760			110	25010	25010	00203	OTH	256022	921000	7,338.04	Cook, M.
00099	AG0760			110	35040	35040	00231	OTH	256022	921000	10,628.73	Dean, M.
00036	TE1000	C03437	0005577251	110	62100	82110		TRAN	442016	183000	1,713.07	Desmond, L.
00036	TE1000	C03437	0005585289	110	62100	82110		TRAN	442016	183000	2,207.95	Desmond, L.
00099	TO9000			110	62100	62100	00233	OTH	256022	566000	3,314.77	Desmond, L.
00099	AG0745			110	63000	63000	00233	OTH	256022	921000	27,314.99	Forth, A.
00099	AG0040			110	19220	19220	00200	OTH	256022	926000	10,798.52	Handsley, V.
00099	AG0245			110	18000	18000	00235	OTH	256022	930200	57,098.17	Henchley, M
00099	DO9000			110	26050	26050	00231	OTH	256022	583000	32,315.84	Hewitt, L.

00001	AG0770	X04502	9000033848	110	56000	56000		OTH	256022	586000	132,279.30	Kinnis, L
00099	AG0760	X08404	9000070726	110	56200	56200	00233	OTH	256022	921000	4,887.72	Lissimore, M.
00099	AG0465			110	16300	16300	00353	OTH	256022	921000	10,719.33	Mead, C
00001	AG0800			110	10500	10500		BDEV	256022	921000	16,648.30	McCormick, T.
00099	DO9110			110	20710	20710	00231	OTH	256022	581000	17,543.39	Miller, D
00099	AG0015			110	19100	19100	00236	OTH	256022	921000	8,008.82	Mostyn, C.
01401	AG0785			110	92433	92433		GAS	256022	880000	23,895.09	Nichols, W.
00095	AG0860			400	17275	17275	00200	OTH	256026	921000	8,541.05	Pearman, A. 50%
00099	AG0760			110	20100	20100	00231	OTH	256022	921000	91,871.43	Pettigrew, J.
00099	DO9000	X06704	9000076168	110	37000	20135	00231	OTH	256022	588000	13,023.42	Pretyman, D.
00099	AG0760			110	26090	26090	00231	OTH	256022	921000	13,138.23	Proudman, N.
00099	DO9000			110	35040	35040	00231	OTH	256022	588000	16,300.75	Reeves, B
00036	TO9000	E06706	9000070599	110	62000	62000		TRAN	256022	566000	7,000.00	Roe, A
00099	TO9030			110	62010	62010	00233	OTH	256022	566000	2,953.70	Roe, L
00099	AG0760			110	10400	10400	00201	OTH	256022	921000	62,298.44	Ryan, L
00036	AG0085	X09545	9000083581	110	10400	10400	00101	DIST	256022	928000		Ryan, L. (NM Mgmt A
00099	AG0745			110	10610	10610	00382	OTH	256022	921000	97,088.77	Sloey, A.
00099	AG0847			200	17980	17980	00380	OTH	256032	921000	28,107.44	Smith, C
00099	AG0270			110	13000	13000	00236	OTH	256022	921000	8,573.64	Stevens, A.
00099	AG0795			110	14200	14200	00201	OTH	256022	921000	57,362.33	Turner, H
00001	AG0730			110	11900	11900		OTH	256022	921000	13,600.23	Vernon-Parry, J
00099	AG0730			110	11200	11200	00382	OTH	256022	921000	69,477.74	Wheatcroft, M
00099	AG0760			110	10850	10850	00233	OTH	256022	921000	123,488.76	Winser, N
00082	AG0760			110	10850	10850		OTH	256022	921000	61,744.38	Winser, N
00001	AG0760			110	10850	10850		OTH	256022	921000	61,744.38	Winser, N.
00099	AG0844	X10705	9000089439	400	17310	17350	00380	OTH	256026	921000	30,791.26	Invoices for Lars Hei
00099	AG0844	B08838	9000089440	400	17310	17350		OTH	524021	174000	21,482.28	Invoices for Lars Hei

00099	AG0844	B08550	9000088503	400	17310	17350		OTH	524021	174000	13,596.85	Invoices for Lars Hei
00099	AG0844	X10485	9000088502	400	17310	17350	00380	OTH	256026	921000	32,973.86	Invoices for Lars Hei
00099	AG0844	B08590	9000088615	400	17310	17350		OTH	524021	174000	204,797.71	Invoices for Lars Hei
00099	AG0040			M10	19120	19120	00236	OTH	256020	926000	35,370.95	Invoices under Steph
00099	AG0730			400	11999	11999	00999	OTH	256026	921000		Adjustment
00099	232444							OTH	611063	232444	-1,981,393.48	Default Account Pre-
00001	234099							OTH	611099	234099	-241,605.22	AP to Assoc Comp
00099	146001							OTH	671099	146001	241,605.22	AR from Assoc Comp
00099	146459							OTH	671099	146459	27,121.06	AR from Assoc Comp
01459	234099							NREG	611099	234099	-27,121.06	AP to Assoc Comp
00036	234099							DIST	611099	234099	-10,921.02	AP to Assoc Comp
00099	146036							OTH	671099	146036	10,921.02	AR from Assoc Comp
00099	146401							OTH	671099	146401	23,895.09	AR from Assoc Comp
01401	234099							GAS	611099	234099	-23,895.09	AP to Assoc Comp
00082	234099							OTH	611099	234099	-61,744.38	AP to Assoc Comp
00099	146082							OTH	671099	146082	61,744.38	AR from Assoc Comp

Lines to add: 1

Totals — Customize | Find | View 5 | First 1-6 of 6 Last

Unit	Total Lines	Total Debits	Total Credits	Journal Status
00001	6	241,605.22	241,605.22	V
00036	5	10,921.02	10,921.02	V
00082	2	61,744.38	61,744.38	V
00099	46	1,981,393.48	1,981,393.48	V
01401	2	23,895.09	23,895.09	V
01459	3	27,121.06	27,121.06	V

Save | Return to Search | Previous in List | Next in List | Notify | Refresh | Add | Update

Header | Lines | Totals | Errors | Approval

JE: 99404

Nov - Mar True up, Expat Bonus and Mar Accrual for Expats that are not Billed

Business Unit	Activity	Segment	Orig. Dept	Chgd Dept.	Billing Pool	Exp. Type	Work Order	Project	Monthly Amount	Bonus Accrual	Adjust	Total	Description	Comments
50001	AG6740	BDEV	56000	56000		200	9000080622	X09085		136.04	17,196.97	17,333.01	Abrain, B	
00092	DO9140	OTH	25044	25044	00203	110				2,450.21	8,705.49	11,155.70	Gessage, K	80%
00099	GO9106	OTH	25044	25044	00206	110				612.55	2,176.37	2,788.93	Gessage, K	20%
00099	AG0994	OTH	92269	92269	00200	110				784.30	6,693.28	7,477.57	Barker, L	50%
00094	AG0993	OTH	92269	92269	00203	110				784.30	6,693.28	7,477.57	Barker, L	50%
00099	AG0760	OTH	86000	86000	00211	110			10,100.00	3,695.90	-	13,795.90	Bingham, P	
00099	AG0805	OTH	12100	12100	00282	110			11,800.00			11,800.00	Boyle, D	
00099	AG0760	OTH	62000	62000	00233	110				1,905.68	377,869.51	379,775.18	Brett, S	
00099	AG0493	OTH	15480	15480	00216	110				4,314.14	27,986.76	32,300.90	Callaghan, J	
[illegible]	AG0990	NREG	25250	25250		110				3,328.61	16,454.42	19,783.03	Connell, C	
[illegible]	AG0760	NREG	25010	25010		110			5,333.33	2,004.70		7,338.03	Cook, M	1/3
00099	AG0760	OTH	25010	25010	00206	110			5,333.33	2,004.70		7,338.03	Cook, M	1/3
00099	AG0760	OTH	25010	25010	00203	110			5,333.34	2,004.70		7,338.04	Cook, M	1/3
00099	AG0760	OTH	35040	35040	00231	110				4,187.96	6,440.77	10,628.73	Dean, M	
00036	TE1000	TRAN	62100	62110		110	0005577251	C03117	$ 1,713.07		-	1,713.07	Desmond, L	45/176
00036	TE1000	TRAN	62100	62110		110	0005585289	C03117	$ 2,207.95		-	2,207.95	Desmond, L	58/176
00099	TO8000	OTH	62100	62100	00233	110			$ 2,778.98	535.80	-	3,314.77	Desmond, L	73/176
00099	AG6745	OTH	63000	63000	00233	110				1,827.31	25,487.68	27,314.99	Feith, A	
00099	AG0040	OTH	19220	19220	00208	110				136.04	10,662.48	10,798.52	Handsley, V	
00099	AG0245	OTH	18000	18000	00235	110				3,576.14	53,522.03	57,098.17	Hinchley, M	
00099	DO9000	OTH	26090	26090	00231	110				3,682.39	28,633.45	32,315.84	Hewitt, L	
00001	AG0720		56000	56000		110	9000033848	X04502		1,953.27	130,326.03	132,279.30	Kiang, L	
00099	AG6760	OTH	56200	56200	00233	110	9000076736			3,041.69	1,846.03	4,887.72	Lissimore, M	
00099	AG6465	OTH	16300	16300	00353	110				1,454.54	9,264.79	10,719.33	Mead, C	
50001	AG0800	BDEV	10500	10500		110			12,300.00	4,348.30	-	16,648.30	McCormick, F	
00099	DO9110	OTH	20710	20710	00231	110				1,439.76	16,103.63	17,543.39	Miller, D	
00099	AG0015	OTH	19100	19100	[illegible]	110			7,000.00	1,008.82	-	8,008.82	Mosvik, C	
01401	AG0785	GAS	92433	92433		110				1,468.67	22,426.42	23,895.09	Nichols, W	
00099	AG0860	OTH	17275	17275	00200	400			7,200.00	1,341.05	-	8,541.05	Pearman, A 50%	
00099	AG0760	OTH	20100	20100	00231	110				24,561.40	67,310.03	91,871.43	Pettigrew, J	
00099	DO9800	OTH	20050	20135	00231	110	9000076168	X06704		3,414.54	10,508.88	13,923.42	Pietsman, D	
00099	AG0760	OTH	26090	26090	[illegible]	110				5,319.84	7,818.39	13,138.23	Proudman, N	
00099	DO9000	OTH	15040	15040	00231	110				451.01	15,939.74	16,390.75	Reeves, B	
00036	TO9000	TRAN	62000	62000		110	9000070599	E06703	7,000.00		-	7,000.00	Roe, A	
00099	TO9100	OTH	62010	62010	00233	110				117.24	2,836.46	2,953.70	Roe, L	
00099	AG0760	OTH	19400	19400	00201	110				11,985.96	50,312.48	62,298.44	Ryan, L	100%
00036	AG0085	DIST	10400	10400	00101	110	9000083581	X09545			-	-	Ryan, L (NM Mgmt Audit)	0%
00099	AG6745	OTH	10610	10610	[illegible]	110				16,407.02	80,681.75	97,088.77	Sloey, A	
00099	AG0847	OTH	17980	17980	00155	200				1,187.71	26,919.73	28,107.44	Smith, C	
00099	AG0270	OTH	13000	13000	00236	110				922.59	7,651.05	8,573.64	Stevens, A	
00099	AG0295	OTH	14200	14200	00201	110				4,568.42	52,793.91	57,362.33	Turner, H	
00001	AG0730	OTH	11900	11900		110				2,773.56	10,826.67	13,600.23	Vernon-Parry, J	
00099	AG0738	OTH	11200	11200	00342	110				6,633.30	82,844.44	89,477.74	Wheatcroft, M	
00099	AG0760	OTH	10850	10850	00213	110					123,488.76	123,488.76	Winser, N	50%
00062	AG0760	OTH	10850	10850		110					61,744.38	61,744.38	Winser, N	25%
00001	AG0760	OTH	10850	10850		110					61,744.38	61,744.38	Winser, N	25%
00099	AG0844	OTH	17310	17350	00380	400	9000089439				30,791.26	30,791.26	Invoices for Lars Heimann	1.43
00099	AG0844	OTH	17310	17350		400	9000089440				31,482.28	31,482.28	Invoices for Lars Heimann	Ex Rate
00099	AG0844	OTH	17310	17350		400	9000088501				13,596.85	13,596.85	Invoices for Lars Heimann	
00099	AG0844	OTH	17310	17350	00380	400	9000088507				32,973.86	32,973.86	Invoices for Lars Heimann	
00099	AG0844	OTH	17310	17350		400	9000088615				204,797.71	204,797.71	Invoices for Lars Heimann	
00099	AG0040	OTH	19120	19120	00216	M10					35,370.95	35,370.95	Invoices under Stephane Echasseriau	
00099	AG0730	OTH	11990	11990	99999	400						-	Adjustment	
00099	232444	OTH							(78,100.00)	(132,470.00)	(1,770,823.33)	(1,981,393.52)		

Accruals are made for Expats whose charges have not been booked in the true-up (adjustments) column
[illegible] KS to BPs

Date of Request: March 15, 2010
Due Date: March 25, 2010

Request No. DAG-6
NMPC Req. No. NM 231 DPS 142

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO:

Request: collective bargaining agreements

1. Please provide a listing of (a) each labor agreement currently in effect between the Company and its union(s); (b) the effective date and period of each agreement; and (c) any extensions that have taken place since the initial agreement was negotiated.

2. Please provide copies of all current labor agreements currently in effect, including any extensions of the initial agreement.

3. Please provide a listing of any labor issues currently being discussed and/or negotiated with the Company's unions and the status of any agreements, memorandum of understandings, etc., that will result from these discussions / negotiations.

4. Please identify any labor issues and/or agreements that have been negotiated and agreed upon between the Company and the union subsequent to the start of the historic test year – i.e. October 2008.

5. For each labor issue and/or agreement listed in response to question #4 above, please explain, provide details, and identify where in the Company's electric rate case filing, the resulting impacts from each have been reflected.

Response:

1(a) A. Agreement Between Niagara Mohawk Power Corporation and Local Union 97
B. Agreement Between Niagara Mohawk Power Corporation and Local Union 97 (Gold Book)
1(b) A. October 1, 2004 – March 31, 2008
B. November 6, 2007 – September 30, 2012
1(c) A. Agreement extended from April 1, 2008 – March 31, 2011 and Agreement extended from March 31, 2011 – March 31, 2014.

2. Please see attachments 1, 2, 3 and 4.

Form 103

3. Labor issues currently being discussed are:
    - Transmission Line Construction – Currently negotiating changes to the existing Memorandum of Agreement that applies separate work practices to the transmission construction workforce.
    - Distribution Line Construction – Negotiations are completed and implementation is in process. The Memorandum of Agreement applies separate work practices to the distribution construction workforce.
    - Gas crew configuration – Negotiations are ongoing regarding a dispute over the number of employees required for certain gas work.
    - Doble Testing Job Flex – Negotiations are ongoing regarding a reclassification of work. This creates more flexibility around Doble (a company that manufactures power factor test instruments) testing in anticipation of additional substation work.
    - Safety – Fire Retardant Clothing. Negotiations are completed and implementation is in process. This is required to comply with a new OSHA mandate.

4. Please see attachments 5, 6 and 7.

5. To the extent that new employees were added as a result of the agreements listed in response to question # 4, their costs are reflected in the test year for the period they were employed during the test year.

<u>Name of Respondent:</u>
Timothy Rosbrook

<u>Date of Reply:</u>
3/26/2010

Memorandum of Agreement
Niagara Mohawk Power Corporation
And
Local Union 97, IBEW
Regarding
Extension to Labor Agreement

Niagara Mohawk Power Corporation (the "Company") and IBEW Local Union 97 ("Local 97" or the "Union") are parties to an agreement made April 1, 2008 ("Existing Agreement") and have agreed to extend the Existing Agreement and have also agreed on other matters as hereinafter set forth. The terms of the Existing Agreement shall remain in effect for the duration of the extension except as amended below.

i. Duration of Contract

The Company and Union are entering into a three year extension of the Existing Agreement from March 31, 2011 through March 31, 2014.

ii. General Wage Increases

The following base wage increases will take effect:

Effective April 1, 2011 ----- 2.50%
Effective April 1, 2012 ----- 2.50%
Effective April 1, 2013 ----- 2.50%

iii. Employee Benefits

1. Employee Stock Purchase Plan (ESPP), as outlined in Attachment 1
   a. Eligibility – Regular or Part Time employee who works more than 20 hours per week.
   b. Purchase American Depository Shares (ADS) on monthly basis at 10% discounted price.
   c. Each ADS represents five ordinary shares in the Company and are listed on New York Stock Exchange.
   d. Contributions up to 20% of base pay each year.
   e. Plan design in accordance with National Grid ESPP

2.Cash Balance – Supplemental pay credits by Birth Year as outlined in Attachment 2 and temporary supplemental annuity in accordance with Attachment 3. Eligibility; employees not in the "transition group", as set forth in the Pension Plan and hired prior to July 1, 1998. Changes are effective October 1, 2009.

3. Post-retirement Medical for employees hired after ratification of this Agreement and current employees not in the "transition group".

a. Changes are effective October 1, 2009.
b. For Current employees, not in the "transition group":

Eligibility	No change
Pre – 65 plans	Active employee plans
Pre – 65 contribution	Current contribution rules from CBA
Post – 65 plan	Medicare Supplement
Post – 65 contribution	Current contribution rules from CBA

c. For New Hires on or after ratification of this Agreement:

Eligibility	Age 60 or older with 85 points or Age 61 with 10 years service
Pre – 65 plans	Active employee plans
Pre – 65 contribution	Company contributes 2.67% per year of service to a maximum of 80%
Post – 65 plan	Medicare Supplement
Post – 65 contribution	Company contributes $4.50 per month per year of service ($9.00 if married

iv. <u>Grievances</u>. Open Grievances will be jointly reviewed no later than December 30, 2009 and any grievances that cannot be mutually resolved that have been approved by the Union to arbitration, will be scheduled to arbitrate on a "first-in, first-scheduled" basis, unless the open matter is related to an employee discharge, in which case it will be scheduled no later than December 30, 2009.

v. <u>Printing</u>. The Agreement will be reprinted and a joint committee will review the Agreement for the purpose of making edits, additions and deletions, including Schedule A, Appendix D and Appendix E.

vi. <u>Annual Performance Evaluation</u> – the form will be modified at Company discretion to allow for use of one evaluation form that is consistent with all bargaining units at National Grid and the target bonus percentage will be 3.5%.

vii. <u>EDO Operating Model</u>
This new operating model will provide viable improvements and efficiencies necessary to enhance customer service, reliability and cost reduction and includes job security for affected employees, which is further defined under the terms and conditions of this MOA.

Any and all issues that may arise that are not covered by this MOA will be reviewed by the joint committee with the full understanding that the Collective Bargaining Agreement will apply.

I. Employee Impact Programs (EIP).

a. Programs are voluntary and will be offered to active employees who as of July 1, 2009 are occupying the positions in the following job series; Design Representative, Office Technician, Consumer Representative, Designer, Meter Mechanic (Lab only), Meter Shop Tester C, Lab Technician, Chief Tester and Installer, and Tree Trimmer at the time of this agreement, whose position is affected by EDO Transformation.
b. Offers will be made at least thirty days prior to the scheduled job reduction and will be made on the basis of division seniority to affected employees in the Eastern and Western divisions and on the basis of geographic area seniority as defined by Article IV 6(b) of the Labor Agreement, in the Central division. The number of eligible employees will be determined by the number of stated reductions associated with the operating model staffing.

1. Voluntary Separation
   a. 2 weeks per year of service, capped at 52 weeks or the parties Separation Allowance benefit, whichever is better based on the individual's age and years of service;
   b. An employee who elects to separate and is eligible for a pension benefit under the terms and conditions of the Collective Bargaining Agreement, will have this benefit paid through the pension asset;
   c. Lump sum payment equal to six months of current Company contribution to medical/dental benefit;
   d. Outplacement services; 30 days from start of service;
   e. Any affected employees who are currently on "Security Clause" status will be eligible for voluntary separation;
   f. Employees electing to separate may be held by the Company up to 18 months in the event the vacancy is to be filled and there are no EITs available for the specific position, or a training need exists.

2. Voluntary Relocation Allowance.
   a. Eligibility: voluntarily accept a position that is located in a work headquarters greater than 50 miles from current. All monetary amounts are less applicable taxes and withholdings and will be paid within thirty business days following Company receipt of signed lease agreement or signed purchase sale agreement.
   b. $5,000 rental or $15,000 primary residence
   c. Any employee who elects to relocate to a non-primary residence and within one year from the start date of their new position and location secures a primary residence, will be eligible to receive the $10,000 difference in benefit.
   d. Lump sum $2,000, paid in year one and year two within thirty days of starting at the new location and then one year after, assuming the employee continues in same or other eligible location.

3. Commuter Allowance. A lump sum of $2,000 less applicable taxes and withholdings will be paid to an employee who commutes to a new location that is located in a work headquarters greater than 50 miles from the current. This payment will be made for the first year only and within thirty days of starting at the new location. The employee will remain eligible for the voluntary relocation allowance for one year from the start date of their new position and location.

4. Any employee whose work headquarters is greater than 50 miles, and who accepted an Office Technician position posted in February/March 2009 will be eligible for the voluntary relocation and commuter allowance.

II. Employee in Transition (EIT) Process. An EIT is an employee displaced as a result of implementing the EDO operating model. Unless modified by this Agreement, the seniority provisions of the Labor Agreement will apply. This is a transition pool and includes the following general provisions. More specific provisions regarding each affected job title are included in this document.

1. Placement into available vacancies in accordance with Article IV of the Labor Agreement.
2. EIT can bid posted positions without loss of wage protection. A successful award, sustaining the employee's rate of pay, will be allowed one time only and the employee status will be plus rated, but not subject to the terms and conditions of "security clause" administration (i.e. they are "made whole").
3. Placement into progression positions to allow for progression to higher level; principles of automatic progression will apply.
4. Transcending rights in accordance with Appendix A of the Labor Agreement.
5. The Company will continue to explore job opportunities for EITs and additional training options will be provided by the Company for consideration of longer term career opportunities at National Grid.

III. Bargaining Unit Positions

By April 1, 2010 the Company will conduct a joint review with IBEW Local 97, of EDO staffing for short term and mid term business planning. The review will include age, position and location of EDO field workforce employees and planned staffing needs for the business cycle.

IV. Design

1. EDO Distribution Design will be centralized to Syracuse. A certain number of Design Investigator positions will be assigned to divisional locations in accordance with the terms defined by this Agreement.

2. Contractors
    a. For the term of the Labor Agreement, consignment type contractors will be discontinued in Distribution Design prior to the displacement of employees into the EIT pool through the implementation of centralized

Design. Gas Design contracting is addressed in the side letter regarding Gas Design Representatives.

b. The model staffing number for the EDO Design Investigator position will be "protected" at East (16), Central (17) and West (17). While contractors (MSA type) are in use in the division, 10 Design Representatives will be retained as follows; 4 in the East, 2 in Central and 4 in the West.
c. Protected means that these jobs will not be reduced so long as EDO Design Representatives remain as EIT in the geographic area.
d. Article IV of the Labor Agreement applies to both centralized Design and Design Investigators. The provisions of the Article will be administered for Centralized Design as follows: the number of Design Representatives being offered overtime opportunities in the divisional roles will determine the number of employees offered overtime in the centralized role, but will not exceed the FTE equivalent of MSA contractors in use, in the division, at the time.
e. If a design contractor is in use in a work location that no longer includes Design Representatives, the geographic area will be used to determine the application of contractor overtime described in Article IV of the Labor Agreement.

3. Employees in Transition (EIT)
    a. Design EITs will be temporarily assigned to a Design role and will be located within their original geographic area, to support the successful implementation of centralized Design.
    b. Employees assigned to these temporary roles will be a part of the transition pool and will be subject to the EIT process.
    c. Employees assigned to a Design Representative position at the time of this Agreement will continue job progression while in the EIT process as a result of the temporary design type work they are performing.
    d. EIT Design Representatives are eligible for contractor related overtime described in Article IV.
    e. Design vacancies will be filled by placing Design EITs based on seniority, from the same geographic area. If there are no Design EITs in the same geographic area, Design EITs in the division, then by system, can volunteer by seniority to fill the vacancy. If there are no volunteers, management will determine whether or not the vacancy is to be filled.

4. In full resolution of System Grievance 1-S-08, Design employees who were eligible as of 8/7/06 to progress to pay level 21.5 will be made whole for the step 1 time period they were required to serve. Employees occupying Design Representative Positions at the time this agreement is signed, and who are covered by Section 3 (d) of the Memorandum of Agreement Regarding Design Representatives (Design Representative MOA), who are assigned to staff divisional Design Investigator positions or who relocate to the Centralized Design office from a work location greater than 50 miles, will progress to PG 21.5 of the MOA and will serve step1 time period.

5. The Design Representative MOA will be amended to include the following provisions and as outlined in Attachment 4:
    a. Provision for centralized design work.
    b. Provision for a field investigator.
    c. Employees may perform all functions of the Design Representative in accordance with the job specification and pay level.
    d. Employees in EDO Design will become a separate work group from Gas Design.
    e. New entrants to series must have 2 year degree in Electrical or Mechanical Technology. Electrical ICS courses are discontinued as a qualifying measure for new entrants to the series.
    f. New entrants to series progress to B level only
    g. C Level duties: services requiring 3 phase primary metering, underground networks, large circuit rebuilds, manholes and ducts, lashed cable, 3 phase UCD, large public works (underground and overhead) and relocations, complex DOT jobs and relocations.
    h. Training for field function of the Design Investigator role will be provided by the Company and with input from Local 97, IBEW.
    i. Concurrent with the centralization of Design, there will be an addition of 3 Right of Way Agent (ROW) A positions and 2 Office Technicians for Easement work. ROW; Watertown, Syracuse and Northeast region. Office Technician; Buffalo and Albany.
    j. The "No - Site Visit" arbitration decision is set aside and the Company is not required to make site visits.

6. Joint Committee. The Company and Union will meet quarterly to review the implementation of the new Design model. The purpose of this meeting will be to ensure successful implementation of the model in cooperation with Local 97. The committee will meet for six quarters and then mutually determine if additional meetings are necessary.

V. Clerical

1. The Office Technician function in EDO Distribution Support Services will be centralized to Syracuse. A limited number of positions will remain staffed at management's discretion in the division operations. The number of positions staffed will be 8 in Central, 7 in West and 7 in the East. These divisional staffing numbers include the provision for five positions described in paragraph V(7) below.

2. Administrative Clerk A:
    a. Pay Group 1 and covered by the Labor Agreement
    b. New job specification is described in Attachment 5.
    c. February 2009 posting of up to 20 positions will be completed by filling the remaining 7 positions as new hires, under the PG 1 job specification.

   d. 10 new positions at PG 1 will be posted immediately.

3. "Gold Book" job specification.
   Company will post 5 new positions under Gold Book model to staff EDO Distribution Support. This new job specification is described in Attachment 6 and will remain as part of the EDO Distribution Support organization and as part of the labor agreement that covers "Gold Book" positions.

4. Additional positions of Pay Group 1, Gold Book or Office Technician A-C, will be posted based on the job specifications and operational need.
5. Two Senior Office Technician positions will be posted in Syracuse upon staffing 40 new centralized clerical positions. An additional two senior Office Technician positions will be posted to correspond with the expansion of clerical staff, as determined by the Company, but corresponding to the staffing of an additional 40 positions. Any employee currently occupying the Senior Office Technician job title, who remains staffed in the organization, will retain this job title until attrition.

6. Contractors performing Office Technician work in Electric and Gas Distribution Support will be discontinued prior to displacing any active employees as a result of centralizing EDO clerical work into Syracuse and will only be further utilized while employees are in transition (EIT concept) if there is a compelling reason as determined by the Company.

7. The Work Coordinator role is an integral part of the management team and is not structured as a role that performs bargaining unit work.

   a. The Company will meet quarterly to conduct a joint review with Local 97 on the implementation of the Work Coordinator role and Centralized Clerical model.
   b. A total of Five (5) additional Office Technician positions (2 East, 1 Central, 2 West) will be retained across the three divisions while EDO clerical employees remain in the EIT pool.
   c. Disputes regarding bargaining unit work will be reviewed and discussed with the intent of creating mutually acceptable resolutions.
   d. The Union will hold in abeyance, its grievances on Work Coordinator.
   e. The joint committee will mutually agree whether or not to continue to meet after six quarters. Employees in Transition (EIT) will be temporarily assigned to a divisional Clerical role within their geographic area, to support the successful implementation of centralized Clerical. Employees assigned to these temporary roles will be placed into the transition pool and will be subject to the EIT process described in Section II above.

8. Employees in EDO Office Technicians positions will be separate from Gas Office Technicians after canvassing to staff available jobs in accordance with the Falletta/Rosbrook letter dated March 2008, unless otherwise mutually agreed.

VI. Maps and Records. The job specifications are changed to create qualifications surrounding the use and application of current GIS technologies and are outlined in Attachment 7 with the Memorandum of Agreement describing the change.

1. MOA and Job Specification as addendum to Engineering Mutual Agreement.
2. New position requires 2 Year (AAS) degree in GIS/Computer Science or two years work experience in GIS. If the candidate in question was an incumbent employee at the time of this agreement, equivalent experience will be considered.
3. Five existing contractors will be replaced with the staffing of this new position over the next two years and will continue to be replaced as the new position is staffed at the qualified level. This does not change Article IV of the Labor Agreement.
4. Files and reproduction type work from the substations group in New England will be transferred to Syracuse in the fall of 2009.

VII. Customer Order Fulfillment. Functions in part, of the Design Representative, Customer Representative, Consumer Representative and Office Technician will be reassigned in the fall of 2009 to a centralized, affiliate workforce in Massachusetts. The centralized workforce will perform new and upgraded service requests, new lighting installations, and a limited variety of other non-service customer requests to provide a single point of accountability. In addition, the work group will review and monitor miscellaneous customer requests that require EDO investigation and involvement.

1. Up to seven Consumer Representatives will be affected across the three divisions. As a result, the Consumer Representatives in the Business Services Department will be eligible to participate in the EIP and EIT programs described in Sections I and II above. Geographic protection applies to affected employees.
2. Customer Representatives. There will be no reduction in occupied positions as a result of work being reassigned to Customer Order Fulfillment.
3. The impact on Office Technicians and Design Representatives is addressed separately above.

VIII. Work Readiness. This new job specification will be staffed to ensure the field force is able to successfully start and end their shifts and enable the execution of work. The Work Readiness job duties are outlined in the job specification of Attachment 8.

1. Locations. The Work Readiness position will be staffed in the following locations; Central 9, East 6, West 4.
2. 19 positions will be posted
3. Pay level of the position is 11

IX. Regional Control. Consolidation of the three operating centers is under review. The Company and Union will cooperatively bargain the impacts of consolidation, including changes to the existing job specifications. In the event that consolidation plans change, an Article XXIII review of the job specifications will continue.

X. Labs. Rubber Goods and Standards will be consolidated to Syracuse from New England and Long Island.

1. Memorandum of Agreement and new job specification relative to the Laboratory Technician A (Dielectric), Attachment 9
2. Revised spec for Lab Tech A (Electric), Attachment 10
3. New job spec for "Materials Handler", pay group 12, Attachment 11
4. All Lab employees will be offered separation in accordance with the EIP program described in section I. A total of four positions will be reduced; 2 Standards Labs and 2 Chem Labs. The four affected employees will be placed into other Lab positions and in accordance with Articles IV and XI of the Labor Agreement.

XI. Make Taps Permanent. Licensed electricians to complete the permanent connections using connectors provided by Company, for single phase, single meter, residential service upgrades up to 200 amps with the same point of attachment. Service Representative Completes the sealing of the meter and review of the site to ensure the service meets company standards. Electric Line Mechanics will be offered an additional 7 weeks of contractor related overtime (in accordance with Article IV); three weeks prior to May 1 and four weeks starting September 1. Upon ratification, employees will be eligible for the offer period to commence after September 1.

XII. Forestry. Effective April 1, 2011 the Company will discontinue in-house forestry work and utilize a fully outsourced model for this type of work.

1. Affected employees will have the voluntary option to choose other EDO jobs as outlined in Attachment 12.
2. Affected employees are eligible for separation allowance described above in EIP.
3. Forestry employees are eligible for the provisions listed in paragraphs 2 and 3 under Section II (EIT Process).
4. Employees who opt not to separate or transition to other EDO positions will remain in their job and geographic area performing forestry duties through March 31, 2011 at which time the in-house forestry work will discontinue.
5. Divisional security clause rules will apply and placement will be made into available jobs effective April 1, 2011.
6. This event will not result in the determination by the Company that no jobs are available.

XIII. Proficiency Checklist
The Memorandum of Agreement on the Role of Chief Line Mechanic in On-the-Job Training and Evaluation will be expanded to include the following Field Operation job series and the role of the applicable Chief position or higher level employee. Time will be assigned during the regular schedule to provide on-the-job training to other employees in

the apprentice role. A joint committee will develop a checklist of duties for the following job series:

- Electrician (Stations)
- Splicer
- Maintenance Mechanic (Stations)
- Maintenance Mechanic (UG)
- Mechanic (UG)
- Relay Tester
- Communications Tester
- Field Tester

XIV. Niagara Falls

1. Combine displaced Buffalo EDO Office Technicians with Collections Service Associates to create a resource pool.
2. The EIT process will apply to all employees in this resource pool and geographic protections will apply.
3. The employees are eligible for the EIP programs.
4. Assignment of work can be within the Technical, Office and Clerical classifications and is at the discretion of management. The Universal Representative MOA applies to employees in this resource pool .
5. Virtual work model will be implemented for the Syracuse Contact Center including calls and WFM.

Signed and Agreed:

LOCAL Union 97, IBEW:	Niagara Mohawk Power Corporation:
David S Falletta	Timothy T. Rosbrook
David S. Falletta President, Business Manager And Financial Secretary	Timothy T. Rosbrook Director, Employee and Labor Relations Upstate New York
July 29 2009	July 29, 2009

Date of Request: March 15, 2010
Due Date: March 25, 2010

Request No. DAG-9
NMPC Req. No. NM 234 DPS 145

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Legal Services Expense

1. Please provide both the HY actual amount for HYEs 9/20/2009 and 9/30/2008, and also the RY forecasted amounts for legal services expense; identify where those stated amounts can be found in the Company's exhibits and workpapers. If the amounts cannot be explicitly derived from the exhibits and workpapers, please provide a listing of charges by expense type, originating business units, direct and indirect charges, and activity number with activity description, along with vendor names (see the Company's response to DAG-14 (NM-144), in Case 08-G-0609 if this question cannot be responded to in the exact format asked. As an alternative, Attachment 2 of DAG-14 could be updated for historic years 2008 and 2009).

2. Please (a) provide all normalizing adjustments the company made to HY legal services expense; and (b) explain and provide a copy of the analysis the Company undertook to determine the actual HY legal services expense that needed to be normalized, in forecasting RY levels.

3. If the answer to question 2 above is, "There are no normalizing adjustments made to the HY," please explain and provide a copy of the analysis the Company undertook to determine the actual HY legal services expense was reasonable and included no non-recurring items, in forecasting the RYs.

Response:
Part 1. 1. In accordance with regulatory policy, the Company's O&M expense exhibit RRP-2 is presented by functional group, subdivided between Operation and Maintenance, with separate schedules for different cost elements (i.e. expense types). The Revenue Requirement Panel testimony describes the exhibit in further detail. Legal Services are not defined by a single expense type (cost element) in the Company's general ledger, and therefore are not presented explicitly in the Company's exhibits or workpapers. Please see attached file DAG-9 Attachment 1 (Legal Services) for requested information on legal services costs as an update to the The Company's response to DAG-14 (NM-144), in Case 08-G-0609.

Form 103

Part 2. As explained above in Part 1, the Company presented O&M expenses for the Historic Year, Historic Year Normalizing Adjustments and Rate Year Adjustments by expense type, not by organization or department (i.e. "Legal Services"). For example, Historic Year Adjustments were made to various expense types to remove non-recurring New England and KeySpan integration costs. Exhibit RRP-10, Workpaper to RRP-2, Schedule 1, Workpaper 3 show how these costs by expense type (supportive of RRP-2), regardless of what department was charged.

Part 3. To comply with regulatory policy, the Company's approach to the review of Historic Year data was organized principally by expense type. For each expense type, the Company queried Historic Year (HY) data generally including information deemed relevant to the specific expense type (i.e. Company, Department, Activity, Segment, Bill Pool, Project, etc). Exhibit RRP-10, Workpaper to RRP-2, Sehedule 1, Workpaper 1 – 7 is the result of this work. As described in The Company's response to Part 1.a and .b of IR DPS 138 DAG-4 on March 23, 2009, an analysis was done on all expense types by project to analyze year over year variance and scrutinize projects for purposes of normalizing the historic test year. In addition, finance representatives from lines of business and shared service groups met regularly with regulatory personnel as part of the RCS process, described in the previous sited IR DAG-4, Part 9, to review year on year variance analysis between historic test year and forecasted rate year. These individuals were provided a high-level functional profile of the HY costs and asked to review this data and to address the following:

- Identify one time costs in the HY that may not be recurring in future years
- Review prior period costs booked in the HY
- Identify any corrections, transfers, adjustments etc.
- Identify any new major initiatives (not in HY) excluding NE Gas and KeySpan Costs to Achieve and Synergy Savings that would be incurred in Calendar Years 2011 through 2013
- Provide detailed descriptions of historic year costs and the impact on rate year.

As a result of these processes there were no one-time costs identified specific to the legal group nor a specific document showing a normalization adjustment to legal expense is not warranted.

<u>Name of Respondent:</u>
James Molloy

<u>Date of Reply:</u>
March 26, 2010

Niagara Mohawk Power Corporation (Gas) d/b/a National Grid
Consultants - Expense Type 100, 105, 110 Legal Services

		Historic Year Ending September 30, 2009			3.21% Rate Year 2011	1.80% Rate Year 2012	1.90% Rate Year 2013
Business Unit		**Total**	**Electric**	**Gas**	**Electric**	**Electric**	**Electric**
99 AP (see List)		267,044.58	243,738.66	23,305.92			
36 AP (see List)		7,513,397.76	6,439,523.14	1,073,874.62			
99 On Line JE		56,976.41	48,537.54	8,438.87			
36 On Line JE	a	26,311.32	42,654.41	(16,343.09)			
Total		7,863,730.07	6,774,453.74	1,089,276.33	6,992,223.42	7,118,083.44	7,253,327.02
	Total Book	7,863,730.42	6,774,453.95	1,089,276.47			
		(0.35)	(0.21)	(0.14)			
	Total A/P Report by Vendor	8,175,217.38	7,063,230.23	1,111,987.15			
	Difference	(311,486.96)	(288,776.28)	(22,710.68)			

Difference Reconciled

	Total	Electric	Gas
Net Legal Accrual for Year (Online JE 01089)	$ (169,050.00)	$ (151,020.30)	$ (18,029.70)
A/C Rec data	$ (171,618.81)	$ (161,843.33)	$ (9,775.48)
Other	29,181.85	24,087.35	5,094.51
	$ (311,486.96)	$ (288,776.28)	$ (22,710.68)

Note

a) Includes $394,775 of Keyspan A/P included in Vendor Report

Outside Legal Services - Exp Type 100 Consultants and 110 Contractors
Historic Years Ending September 2008 and 2009 - By Originating Business, By Vendor, By Activity
Total Charged Through Accounts Payable System and Total Charged to Niagara Mohawk Electric & Gas
(Whole $)

								Historic Test)Data Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	Orig Business Unit	Vendor	Activity	Activity Descr	Business Unit	Segment	Billing Pool	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric
Niagara Mohawk Power Corp	00036	ALSTON & BIRD LLP	AG0236	AGC General Litigation	00036	DIST	00100	143,375.60	24,373.85	119,001.75	285,507.93	48,536.35	236,971.58
			AG0245	Corporate Matters/Contracts	00036	DIST	00100	17,157.97	2,916.85	14,241.12	7,956.60	1,352.62	6,603.98
						TRAN		169,117.70	0.00	169,117.70	2,096.00	0.00	2,096.00
			AG0253	AGC FERC	00036	DIST					16,858.80	0.00	16,858.80
			AG0255	Regulatory Legal Services	00036	DIST		26,586.44	0.00	26,586.44	437,233.15	0.00	437,233.15
							00100	2,080,183.53	353,631.20	1,726,552.33	947,431.48	161,063.35	786,368.13
							00101				289,928.00	0.00	289,928.00
						TRAN		853,536.79	0.00	853,536.79	608,005.40	0.00	608,005.40
		ALSTON & BIRD LLP Total						3,289,958.03	380,921.91	2,909,036.12	2,595,017.36	210,952.32	2,384,065.04
		AMDURSKY PELKY FENNELL & WALLEN PC	AG0233	Legal Compl Manfc Gas Plant NY	00036	GAS		351.00	351.00	0.00			
			AG0235	General Legal Claims	00036	DIST					1,080.00	0.00	1,080.00
		AMDURSKY PELKY FENNELL & WALLEN PC Total						351.00	351.00	0.00	1,080.00	0.00	1,080.00
		AMERICAN LEGAL SERVICES INC	AG0235	General Legal Claims	00036	DIST					700.00	0.00	700.00
		AMERICAN LEGAL SERVICES INC Total									700.00	0.00	700.00
		ANDERSON & KREIGER LLP	AG0232	Environ Legal Compl A&G NE	00036	DIST	00100				10,012.60	1,702.14	8,310.46
		ANDERSON & KREIGER LLP Total									10,012.60	1,702.14	8,310.46
		AT&T	AG0245	Corporate Matters/Contracts	00036	DIST	00100				207.41	35.26	172.15
		AT&T Total									207.41	35.26	172.15
		BOND SCHOENECK & KING PLLC	AG0236	AGC General Litigation	00036	DIST		5,766.51	0.00	5,766.51			
							00100	18,116.28	3,079.77	15,036.51	17,334.85	2,946.92	14,387.93
			AG0240	SVP US General Counsel	00036	DIST		31,565.49	0.00	31,565.49	96,314.99	0.00	96,314.99
							00100	418,593.49	71,160.89	347,432.60	428,319.36	72,814.29	355,505.07
			AG0242	AGC Labor & Employment	00036	DIST					11,025.15	0.00	11,025.15
							00100				27,219.75	4,627.36	22,592.39
		BOND SCHOENECK & KING PLLC Total						474,041.77	74,240.66	399,801.11	580,214.10	80,388.57	499,825.53
		BOWDITCH AND DEWEY LLP	AG0235	General Legal Claims	00036	DIST		5,825.09	0.00	5,825.09	504.90	0.00	504.90
			AG0236	AGC General Litigation	00036	DIST		1,850.35	0.00	1,850.35			
							00100	229.92	39.09	190.83	8,461.42	1,438.44	7,022.98
		BOWDITCH AND DEWEY LLP Total						7,905.36	39.09	7,866.27	8,966.32	1,438.44	7,527.88
		CLOUGH HARBOUR & ASSOCIATES LLP	AG0236	AGC General Litigation	00036	DIST					3,175.21	0.00	3,175.21
		CLOUGH HARBOUR & ASSOCIATES LLP Total									3,175.21	0.00	3,175.21
		CULLEN AND DYKMAN LLP	AG0080	Regulatory Filing Activities	00036	GAS		95,981.17	95,981.17	0.00	290,808.26	290,808.26	0.00
		CULLEN AND DYKMAN LLP Total						95,981.17	95,981.17	0.00	290,808.26	290,808.26	0.00
		DAVID J MAGNARELLI	AG0235	General Legal Claims	00036	DIST		22,902.40	0.00	22,902.40	27,532.26	0.00	27,532.26
		DAVID J MAGNARELLI Total						22,902.40	0.00	22,902.40	27,532.26	0.00	27,532.26
		DRINKER BIDDLE & REATH LLP	AG0232	Environ Legal Compl A&G NE	00036	DIST	00100				32,292.00	5,489.64	26,802.36
		DRINKER BIDDLE & REATH LLP Total									32,292.00	5,489.64	26,802.36
		EDWARDS ANGELL PALMER & DODGE LLP	AG0245	Corporate Matters/Contracts	00036	DIST	00100	10,019.35	1,703.29	8,316.06	16,422.87	2,791.89	13,630.98
		EDWARDS ANGELL PALMER & DODGE LLP Total						10,019.35	1,703.29	8,316.06	16,422.87	2,791.89	13,630.98
		FINNEGAN HENDERSON FARABOW GARRETT &	AG0245	Corporate Matters/Contracts	00036	DIST	00100	1,008.60	171.46	837.14	1,222.27	207.79	1,014.48
		FINNEGAN HENDERSON FARABOW GARRETT & Total						1,008.60	171.46	837.14	1,222.27	207.79	1,014.48
		GREENBERG TRAURIG LLP	AG0236	AGC General Litigation	00036	DIST		1,327.50	0.00	1,327.50	3,325.00	0.00	3,325.00
		GREENBERG TRAURIG LLP Total						1,327.50	0.00	1,327.50	3,325.00	0.00	3,325.00
		GREENE HERSHDORFER & SHARPE	AG0235	General Legal Claims	00036	DIST		40,201.89	0.00	40,201.89	38,707.52	0.00	38,707.52
		GREENE HERSHDORFER & SHARPE Total						40,201.89	0.00	40,201.89	38,707.52	0.00	38,707.52
		HARRIS BEACH PLLC	AG0236	AGC General Litigation	00036	DIST		20,527.92	0.00	20,527.92	23,828.00	0.00	23,828.00
			AG0255	Regulatory Legal Services	00036	DIST	00100	150,459.10	25,578.05	124,881.05	50,000.00	8,500.00	41,500.00

Outside Legal Services - Exp Type 100 Consultants and 110 Contractors
Historic Years Ending September 2008 and 2009 - By Originating Business, By Vendor, By Activity
Total Charged Through Accounts Payable System and Total Charged to Niagara Mohawk Electric & Gas
(Whole $)

								Historic Test Data Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	Orig Business Unit	Vendor	Activity	Activity Descr	Business Unit	Segment	Billing Pool	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric
		HARRIS BEACH PLLC Total						170,987.02	25,578.05	145,408.97	73,828.00	8,500.00	65,328.00
		HISCOCK & BARCLAY LLP	AG0233	Legal Compl Manfc Gas Plant NY	00036	DIST					4,219.27	0.00	4,219.27
			AG0235	General Legal Claims	00036	DIST		314,746.71	0.00	314,746.71	347,921.53	0.00	347,921.53
							00100	95,269.16	16,195.76	79,073.40	2,604.90	442.83	2,162.07
						GAS		9,484.05	9,484.05	0.00	34,337.89	34,337.89	0.00
			AG0236	AGC General Litigation	00036	DIST		4,134.34	0.00	4,134.34	54,628.40	0.00	54,628.40
							00100	585,611.89	99,554.02	486,057.87	783,759.65	133,239.14	650,520.51
						TRAN		8,813.08	0.00	8,813.08	8,557.39	0.00	8,557.39
			AG0245	Corporate Matters/Contracts	00036	DIST	00100	27,862.02	4,736.54	23,125.48	102,930.28	17,498.15	85,432.13
			AG0252	DGC Federal and NY Regulatory	00036	DIST	00100				2,202.00	374.34	1,827.66
			AG0254	AGC NY Regulatory	00036	DIST					14,710.70	0.00	14,710.70
			AG0255	Regulatory Legal Services	00036	DIST		360,867.39	0.00	360,867.39	610,343.65	0.00	610,343.65
							00100				42,450.30	7,216.55	35,233.75
						TRAN		660.00	0.00	660.00	390.00	0.00	390.00
			AG0260	AGC Real Estate	00036	DIST					40,818.42	0.00	40,818.42
							00100	8,148.54	1,385.25	6,763.29	15,107.52	2,568.28	12,539.24
		HISCOCK & BARCLAY LLP Total						1,415,597.18	131,355.62	1,284,241.56	2,064,981.90	195,677.18	1,869,304.72
		JEANNE O'CONNELL RPR	AG0080	Regulatory Filing Activities	00036	DIST					3,674.74	0.00	3,674.74
		JEANNE O'CONNELL RPR Total									3,674.74	0.00	3,674.74
		JOHN SERTH JR PE	AG0236	AGC General Litigation	00036	DIST		610.00	0.00	610.00	125.00	0.00	125.00
		JOHN SERTH JR PE Total						610.00	0.00	610.00	125.00	0.00	125.00
		JOHN U H BLUMENSTOCK ESQ	AG0236	AGC General Litigation	00036	DIST					2,942.17	0.00	2,942.17
							00100	141,989.99	24,138.30	117,851.69	154,790.90	26,314.45	128,476.45
		JOHN U H BLUMENSTOCK ESQ Total						141,989.99	24,138.30	117,851.69	157,733.07	26,314.45	131,418.62
		MORGAN LEWIS & BOCKIUS LLP	AG0255	Regulatory Legal Services	00036	DIST	00100	170,372.00	28,963.24	141,408.76	894,293.64	152,029.92	742,263.72
		MORGAN LEWIS & BOCKIUS LLP Total						170,372.00	28,963.24	141,408.76	894,293.64	152,029.92	742,263.72
		ORRICK HERRINGTON & SUTCLIFFE LLP	AG0236	AGC General Litigation	00036	DIST		2,775.75	0.00	2,775.75	2,761.50	0.00	2,761.50
							00100	262.50	44.63	217.88	1,938.75	329.59	1,609.16
		ORRICK HERRINGTON & SUTCLIFFE LLP Total						3,038.25	44.63	2,993.63	4,700.25	329.59	4,370.66
		PRO UNLIMITED INC	AG0241	Manager of Operations	00036	DIST	00100				18,913.75	3,215.34	15,698.41
			AG0245	Corporate Matters/Contracts	00036	DIST	00100				8,302.47	1,411.42	6,891.05
		PRO UNLIMITED INC Total									27,216.22	4,626.76	22,589.46
		RICE DOLAN & KERSHAW	AG0236	AGC General Litigation	00036	DIST					608.00	0.00	608.00
		RICE DOLAN & KERSHAW Total									608.00	0.00	608.00
		ROBERT L ADAMS ESQ	AG0235	General Legal Claims	00036	DIST		46,194.59	0.00	46,194.59	57,321.97	0.00	57,321.97
						GAS		662.40	662.40	0.00	867.00	867.00	0.00
			AG0236	AGC General Litigation	00036	DIST		1,824.98	0.00	1,824.98	697.00	0.00	697.00
							00100	2,503.24	425.55	2,077.69	925.40	157.32	768.08
		ROBERT L ADAMS ESQ Total						51,185.21	1,087.95	50,097.26	59,811.37	1,024.32	58,787.05
		ROPES & GRAY LLP	AG0245	Corporate Matters/Contracts	00036	DIST	00100	4,457.50	757.78	3,699.73	11,397.70	1,937.61	9,460.09
		ROPES & GRAY LLP Total						4,457.50	757.78	3,699.73	11,397.70	1,937.61	9,460.09
		RUSSELL R JOHNSON III	AG0236	AGC General Litigation	00036	DIST	00100	48,528.61	8,249.86	40,278.75	9,704.63	1,649.79	8,054.84
		RUSSELL R JOHNSON III Total						48,528.61	8,249.86	40,278.75	9,704.63	1,649.79	8,054.84
		SEYFARTH SHAW ATTORNEYS LLP	AG0240	SVP US General Counsel	00036	DIST					1,560.09	0.00	1,560.09
		SEYFARTH SHAW ATTORNEYS LLP Total									1,560.09	0.00	1,560.09
		SOLOMON AND SOLOMON PC	AG0235	General Legal Claims	00036	DIST		261,371.00	0.00	261,371.00	177,711.06	0.00	177,711.06
		SOLOMON AND SOLOMON PC Total						261,371.00	0.00	261,371.00	177,711.06	0.00	177,711.06

Outside Legal Services - Exp Type 100 Consultants and 110 Contractors
Historic Years Ending September 2008 and 2009 - By Originating Business, By Vendor, By Activity
Total Charged Through Accounts Payable System and Total Charged to Niagara Mohawk Electric & Gas
(Whole $)

								Historic Test Y Data					
								Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	Orig Business Unit	Vendor	Activity	Activity Descr	Business Unit	Segment	Billing Pool	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric
		THE ENERGY ASSOCIATION OF NY STATE	AG0255	Regulatory Legal Services	00036	TRAN		266,155.65	0.00	266,155.65	305,896.16	0.00	305,896.16
		THE ENERGY ASSOCIATION OF NY STATE Total						266,155.65	0.00	266,155.65	305,896.16	0.00	305,896.16
		THE SUBURBAN GROUP	AG0245	Corporate Matters/Contracts	00099	OTH	00235	3,643.37	0.00	0.00			
		THE SUBURBAN GROUP Total						3,643.37	0.00	0.00			
		UPDATE LEGAL INC	AG0245	Corporate Matters/Contracts	00099	OTH	00235	2,054.00	0.00	0.00			
		UPDATE LEGAL INC Total						2,054.00	0.00	0.00			
		WEST GROUP	AG0245	Corporate Matters/Contracts	00036	DIST	00100				710.50	120.79	589.72
		WEST GROUP Total									710.50	120.79	589.72
		WILDER & LINNEBALL LLP	AG0235	General Legal Claims	00036	DIST		117,810.88	0.00	117,810.88	62,054.76	0.00	62,054.76
						GAS		44,608.39	44,608.39	0.00	37,214.33	37,214.33	0.00
		WILDER & LINNEBALL LLP Total						162,419.27	44,608.39	117,810.88	99,269.09	37,214.33	62,054.76
		STENGER & FINNERTY	AG0235	General Legal Claims	00036	DIST		1,386.50	0.00	1,386.50			
		STENGER & FINNERTY Total						1,386.50	0.00	1,386.50			
		MCCONNELL VALDES LLC	AG0236	AGC General Litigation	00036	DIST	00100	12,061.99	2,050.54	10,011.45			
		MCCONNELL VALDES LLC Total						12,061.99	2,050.54	10,011.45			
		BORDEN LADNER GERVAIS LLP	AG0245	Corporate Matters/Contracts	00036	DIST		742.31	0.00	742.31			
		BORDEN LADNER GERVAIS LLP Total						742.31	0.00	742.31			
		MARJAMA MULDOON BLASIAK & SULLIVAN LLP	AG0245	Corporate Matters/Contracts	00036	DIST	00100	3,147.74	535.12	2,612.62			
		MARJAMA MULDOON BLASIAK & SULLIVAN LLP Total						3,147.74	535.12	2,612.62			
Niagara Mohawk Power Corp Total								6,663,444.66	820,778.04	5,836,969.25	7,502,904.60	1,023,239.04	6,479,665.56
National Grid USA Service Co.	00099	ALSTON & BIRD LLP	AG0245	Corporate Matters/Contracts	00099	OTH	00236	41,397.07	3,773.16	18,422.56			
			AG0255	Regulatory Legal Services	00099	OTH	00233	84,198.97	0.00	46,467.06	115,041.19	0.00	63,844.04
							00235	6,501.60	0.00	0.00			
							00236	57,520.70	5,244.29	25,605.40	89,834.34	8,195.22	40,013.38
							00238				68,052.25	0.00	37,063.29
		ALSTON & BIRD LLP Total						189,618.34	9,017.44	90,495.01	272,927.78	8,195.22	140,920.72
		AMERICAN GAS ASSOCIATION	AG0252	DGC Federal and NY Regulatory	00099	OTH	00382				825.00	37.49	222.82
		AMERICAN GAS ASSOCIATION Total									825.00	37.49	222.82
		BOND SCHOENECK & KING PLLC	AG0242	AGC Labor & Employment	00099	OTH	00382				3,407.25	154.83	920.26
		BOND SCHOENECK & KING PLLC Total									3,407.25	154.83	920.26
		BOSTON PROPERTIES LIMITED PARTNERSHIP	AG0245	Corporate Matters/Contracts	00099	OTH	00235	865.41	0.00	0.00	594.00	0.00	0.00
			AG0256	AGC NE Regulatory	00099	OTH	00239				90.00	4.13	24.58
		BOSTON PROPERTIES LIMITED PARTNERSHIP Total						865.41	0.00	0.00	684.00	4.13	24.58
		BOWDITCH AND DEWEY LLP	AG0235	General Legal Claims	00099	OTH	00235	10,868.49	0.00	0.00	219.19	0.00	0.00
			AG0236	AGC General Litigation	00099	OTH	00230				2,477.80	0.00	0.00
							00235	1,669.40	0.00	0.00			
			AG0255	Regulatory Legal Services	00099	OTH	00235	18,700.50	0.00	0.00	7,869.25	0.00	0.00
		BOWDITCH AND DEWEY LLP Total						31,238.39	0.00	0.00	10,566.24	0.00	0.00
		CAPITAL RECORDS MANAGEMENT INC	AG0238	Information Records Managemen	00099	OTH	00235				970.80	0.00	0.00
			AG0245	Corporate Matters/Contracts	00099	OTH	00235				880.36	0.00	0.00
		CAPITAL RECORDS MANAGEMENT INC Total									1,851.16	0.00	0.00
		CURRY PRINTING	AG0253	AGC FERC	00099	OTH	00235				123.83	0.00	0.00
		CURRY PRINTING Total									123.83	0.00	0.00
		DAVID J GORMAN PC	AG0260	AGC Real Estate	00099	OTH	00236	36,847.54	3,348.47	16,349.11	46,019.24	4,183.97	20,428.49
		DAVID J GORMAN PC Total						36,847.54	3,348.47	16,349.11	46,019.24	4,183.97	20,428.49
		EDISON ELECTRIC INSTITUTE (EEI)	AG0493	Provide Administrative & Gener	00099	OTH	00236				12,000.00	1,095.00	5,346.36
		EDISON ELECTRIC INSTITUTE (EEI) Total									12,000.00	1,095.00	5,346.36

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								Historic Test Year Data					
								Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	Orig Business Unit	Vendor	Activity	Activity Descr	Business Unit	Segment	Billing Pool	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric
		EDWARDS ANGELL PALMER & DODGE LLP	AG0240	SVP US General Counsel	00099	OTH	00235	4,434.53	0.00	0.00	21,290.47	0.00	0.00
			AG0245	Corporate Matters/Contracts	00099	OTH	00236	664.94	60.21	293.98	141.32	12.90	62.96
		EDWARDS ANGELL PALMER & DODGE LLP Total						5,099.47	60.21	293.98	21,431.79	12.90	62.96
		ETHICS & COMPLIANCE OFFICER ASSOCIATION	AG0493	Provide Administrative & Gener	00099	OTH	00236				4,500.00	410.63	2,004.89
		ETHICS & COMPLIANCE OFFICER ASSOCIATION Total									4,500.00	410.63	2,004.89
		FINNEGAN HENDERSON FARABOW GARRETT &	AG0245	Corporate Matters/Contracts	00099	OTH	00236	1,520.14	138.16	674.56	352.43	32.16	157.02
							00237				2,372.34	0.00	0.00
		FINNEGAN HENDERSON FARABOW GARRETT & Total						1,520.14	138.16	674.56	2,724.77	32.16	157.02
		GIBSON DUNN & CRUTCHER LLP	AG0245	Corporate Matters/Contracts	00099	OTH	00380				3,689.77	331.24	1,617.32
		GIBSON DUNN & CRUTCHER LLP Total									3,689.77	331.24	1,617.32
		GLENN E DAWSON ESQ	AG0240	SVP US General Counsel	00099	OTH	00232	16,655.99	0.00	0.00	11,971.20	0.00	0.00
							00233				3,408.22	0.00	1,865.57
							00235				1,225.26	0.00	0.00
		GLENN E DAWSON ESQ Total						16,655.99	0.00	0.00	16,604.68	0.00	1,865.57
		GOULSTON & STORRS	AG0260	AGC Real Estate	00099	OTH	00235	223,227.60	0.00	0.00	13,514.64	0.00	0.00
		GOULSTON & STORRS Total						223,227.60	0.00	0.00	13,514.64	0.00	0.00
		HISCOCK & BARCLAY LLP	AG0245	Corporate Matters/Contracts	00099	OTH	00382				752.00	34.17	203.11
			AG0255	Regulatory Legal Services	00099	OTH	00231	9,129.00	0.00	4,801.40	20,136.82	0.00	10,512.17
		HISCOCK & BARCLAY LLP Total						9,129.00	0.00	4,801.40	20,888.82	34.17	10,715.28
		INCISIVE MEDIA	AG0255	Regulatory Legal Services	00099	OTH	00380				600.00	54.09	264.10
		INCISIVE MEDIA Total									600.00	54.09	264.10
		INTERNAL REVENUE SERVICE	AG0245	Corporate Matters/Contracts	00099	OTH	00235				50,241.38	0.00	0.00
		INTERNAL REVENUE SERVICE Total									50,241.38	0.00	0.00
		IRON MOUNTAIN OFF-SITE	AG0238	Information Records Managemen	00099	OTH	00235				11,438.46	0.00	0.00
		IRON MOUNTAIN OFF-SITE Total									11,438.46	0.00	0.00
		IRON MOUNTAIN RECORDS MANAGEMENT	AG0238	Information Records Managemen	00099	OTH	00235				38,863.38	0.00	0.00
			AG0245	Corporate Matters/Contracts	00099	OTH	00235				131,857.15	0.00	0.00
		IRON MOUNTAIN RECORDS MANAGEMENT Total									170,720.53	0.00	0.00
		KELLER AND HECKMAN	AG0255	Regulatory Legal Services	00099	OTH	00231	24,779.25	0.00	13,020.21	21,280.11	0.00	11,133.27
		KELLER AND HECKMAN Total						24,779.25	0.00	13,020.21	21,280.11	0.00	11,133.27
		LANE4 MANAGEMENT GROUP	AG0240	SVP US General Counsel	00099	OTH	00382				10,518.70	477.97	2,841.00
		LANE4 MANAGEMENT GROUP Total									10,518.70	477.97	2,841.00
		LAWSON LEGAL RECRUITERS LLC	AG0245	Corporate Matters/Contracts	00099	OTH	00236				24,400.00	2,226.50	10,870.93
		LAWSON LEGAL RECRUITERS LLC Total									24,400.00	2,226.50	10,870.93
		MASSACHUSETTS DEPARTMENT OF REVENUE	AG0240	SVP US General Counsel	00099	OTH	00235				0.00	0.00	0.00
			AG0245	Corporate Matters/Contracts	00099	OTH	00235				4,958.30	0.00	0.00
		MASSACHUSETTS DEPARTMENT OF REVENUE Total									4,958.30	0.00	0.00
		MCCARTER & ENGLISH LLP	AG0242	AGC Labor & Employment	00099	OTH	00382				15,385.00	699.09	4,155.33
		MCCARTER & ENGLISH LLP Total									15,385.00	699.09	4,155.33
		MCLANE GRAF RAULERSON & MIDDLETON	AG0255	Regulatory Legal Services	00099	OTH	00237				118,905.60	0.00	0.00
			AG0256	AGC NE Regulatory	00099	OTH	00391				390.50	0.00	0.00
		MCLANE GRAF RAULERSON & MIDDLETON Total									119,296.10	0.00	0.00
		MORGAN LEWIS & BOCKIUS LLP	AG0255	Regulatory Legal Services	00099	OTH	00236				1,837.50	166.39	812.40
		MORGAN LEWIS & BOCKIUS LLP Total									1,837.50	166.39	812.40
		NOBLE & WICKERSHAM LLP	AG0255	Regulatory Legal Services	00099	OTH	00236	19,342.85	1,751.50	8,551.86	495.00	45.17	220.54
		NOBLE & WICKERSHAM LLP Total						19,342.85	1,751.50	8,551.86	495.00	45.17	220.54
		NOVA RECORDS LLC	AG0238	Information Records Managemen	00099	OTH	00235				2,865.45	0.00	0.00

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(Whole $)

								Historic Test Year Data Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	Orig Business Unit	Vendor	Activity	Activity Descr	Business Unit	Segment	Billing Pool	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric	Sum of Total Payables $	Sum of Total Payables Gas	Sum of Total Electric
			AG0245	Corporate Matters/Contracts	00099	OTH	00235				8,838.55	0.00	0.00
		NOVA RECORDS LLC Total									11,704.00	0.00	0.00
		PRO UNLIMITED INC	AG0235	General Legal Claims	00099	OTH	00235				1,450.06	0.00	0.00
			AG0241	Manager of Operations	00099	OTH	00235				9,742.16	0.00	0.00
							00382				25,585.84	1,162.62	6,910.48
			AG0245	Corporate Matters/Contracts	00036	DIST	00100	26,069.11	4,431.75	21,637.36	5,854.05	995.19	4,858.86
							00101	304.20	0.00	304.20			
					00099	OTH	00235				49,340.77	0.00	0.00
							00382				5,231.97	238.67	1,399.85
			AG0259	NE Siting	00099	OTH	00235				295.22	0.00	0.00
							00382				1,419.13	64.49	383.29
		PRO UNLIMITED INC Total						26,373.31	4,431.75	21,941.56	98,919.20	2,460.97	13,552.49
		PROFESSIONALS INC	AG0245	Corporate Matters/Contracts	00036	DIST	00100	69,320.68	11,784.52	57,536.16	933.00	158.61	774.39
							00101	691.20	0.00	691.20			
					00099	OTH	00235	10,668.38	0.00	0.00			
							00236	1,836.00	166.25	811.73			
		PROFESSIONALS INC Total						82,516.26	11,950.77	59,039.10	933.00	158.61	774.39
		RICE DOLAN & KERSHAW	AG0236	AGC General Litigation	00099	OTH	00235	6,616.44	0.00	0.00	8,672.90	0.00	0.00
		RICE DOLAN & KERSHAW Total						6,616.44	0.00	0.00	8,672.90	0.00	0.00
		ROPES & GRAY LLP	AG0240	SVP US General Counsel	00099	OTH	00236	37,314.50	3,404.95	16,624.73	14,314.48	1,306.20	6,377.53
		ROPES & GRAY LLP Total						37,314.50	3,404.95	16,624.73	14,314.48	1,306.20	6,377.53
		RUSSELL R JOHNSON III	AG0236	AGC General Litigation	00099	OTH	00231				195.00	0.00	101.60
							00235	1,087.91	0.00	0.00	130.20	0.00	0.00
							00236	867.16	78.98	385.61	450.61	41.12	200.76
		RUSSELL R JOHNSON III Total						1,955.07	78.98	385.61	775.81	41.12	302.36
		SAPIRE SEARCH GROUP	AG0255	Regulatory Legal Services	00099	OTH	00236				15,675.00	1,430.34	6,983.68
		SAPIRE SEARCH GROUP Total									15,675.00	1,430.34	6,983.68
		SKADDEN ARPS SLATE MEAGHER & FLOM	AG0245	Corporate Matters/Contracts	00099	OTH	00382				16,702.00	773.14	4,309.12
		SKADDEN ARPS SLATE MEAGHER & FLOM Total									16,702.00	773.14	4,309.12
		THE SUBURBAN GROUP	AG0245	Corporate Matters/Contracts	00099	OTH	00235	97,767.72	0.00	0.00	1,672.32	0.00	0.00
							00236	562.80	51.36	250.74	337.64	30.81	150.43
			AG0260	AGC Real Estate	00099	OTH	00235	760.54	0.00	0.00			
		THE SUBURBAN GROUP Total						99,091.06	51.36	250.74	2,009.96	30.81	150.43
		UPDATE LEGAL INC	AG0245	Corporate Matters/Contracts	00099	OTH	00235	99,159.45	0.00	0.00	22,869.79	0.00	0.00
							00236	2,054.00	185.99	908.11			
		UPDATE LEGAL INC Total						101,213.45	185.99	908.11	22,869.79	0.00	0.00
		YOUNG SAMUEL CHAMBERS LTD	AG0760	Operations Executive Services	00099	OTH	00354				166.51	10.77	52.60
							00382				1,242.59	57.52	320.59
		YOUNG SAMUEL CHAMBERS LTD Total									1,409.10	68.29	373.19
		THE PROVIDENCE JOURNAL COMPANY	AG0085	Provide Regulatory Support	00099	OTH	00235	64.80	0.00	0.00			
		THE PROVIDENCE JOURNAL COMPANY Total						64.80	0.00	0.00			
		SUTHERLAND ASBILL & BRENNAN LLP	AG0240	SVP US General Counsel	00099	OTH	00236	7,100.18	642.92	3,139.13			
		SUTHERLAND ASBILL & BRENNAN LLP Total						7,100.18	642.92	3,139.13			
		THE AYCO COMPANY L P	AG0245	Corporate Matters/Contracts	00099	OTH	00235	88.41	0.00	0.00			
		THE AYCO COMPANY L P Total						88.41	0.00	0.00			
		JONES DAY	AG0245	Corporate Matters/Contracts	00099	OTH	00235	680.00	0.00	0.00			
		JONES DAY Total						680.00	0.00	0.00			

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								Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	**Orig Business Unit**	**Vendor**	**Activity**	**Activity Descr**	**Business Unit**	**Segment**	**Billing Pool**	**Sum of Total Payables $**	**Sum of Total Payables Gas**	**Sum of Total Electric**	**Sum of Total Payables $**	**Sum of Total Payables Gas**	**Sum of Total Electric**
		RICHARD C MOONEY	AG0255	Regulatory Legal Services	00099	OTH	00235	44,331.73	0.00	0.00			
		RICHARD C MOONEY Total						44,331.73	0.00	0.00			
		REGULATORY WATCH INC	AG0255	Regulatory Legal Services	00099	OTH	00235	216.25	0.00	0.00			
		REGULATORY WATCH INC Total						216.25	0.00	0.00			
		THE BRATTLE GROUP	AG0255	Regulatory Legal Services	00099	OTH	00236	36,481.73	3,328.96	16,253.71			
		THE BRATTLE GROUP Total						36,481.73	3,328.96	16,253.71			
		GE CORPORATE CARD SERVICES	AG0493	Provide Administrative & Gener	00099	OTH	00236	291.31	26.58	129.79			
		GE CORPORATE CARD SERVICES Total						291.31	26.58	129.79			
		RAINBOW MOVERS INC	AG0640	Moves & Relocations	00099	OTH	00235	598.00	0.00	0.00			
		RAINBOW MOVERS INC Total						598.00	0.00	0.00			
National Grid USA Service Co. Total								1,003,256.48	38,418.02	252,858.61	1,056,915.29	24,430.41	247,407.00
Narragansett Electric Company	00049	NOVA RECORDS LLC	AG0245	Corporate Matters/Contracts	00099	OTH	00235				144.68	0.00	0.00
		NOVA RECORDS LLC Total									144.68	0.00	0.00
		ORRICK HERRINGTON & SUTCLIFFE LLP	AG0236	AGC General Litigation	00036	DIST	00100	122.40	20.81	101.59	541.66	92.08	449.58
		ORRICK HERRINGTON & SUTCLIFFE LLP Total						122.40	20.81	101.59	541.66	92.08	449.58
		RUSSELL R JOHNSON III	AG0236	AGC General Litigation	00036	DIST					346.87	0.00	346.87
		RUSSELL R JOHNSON III Total									346.87	0.00	346.87
		SOLOMON AND SOLOMON PC	AG0235	General Legal Claims	00036	DIST		90.00	0.00	90.00	2,114.17	0.00	2,114.17
		SOLOMON AND SOLOMON PC Total						90.00	0.00	90.00	2,114.17	0.00	2,114.17
Narragansett Electric Company Total								212.40	20.81	191.59	3,147.38	92.08	2,910.62
Massachusetts Electric Company	00005	RUSSELL R JOHNSON III	AG0236	AGC General Litigation	00036	DIST					103.77	0.00	103.77
							00100				226.55	38.51	188.04
		RUSSELL R JOHNSON III Total									330.32	38.51	291.81
		EXPONENT INC	AG0255	Regulatory Legal Services	00099	OTH	00235	2,477.50	0.00	0.00			
		EXPONENT INC Total						2,477.50	0.00	0.00			
Massachusetts Electric Company Total								2,477.50	0.00	0.00	330.32	38.51	291.81
National Grid USA	00001	INTERNAL REVENUE SERVICE	AG0245	Corporate Matters/Contracts	00099	OTH	00235				9,680.46	0.00	0.00
			DO9000	Misc Ops Supv and Admin	00099	OTH	00231				3,496.74	0.00	1,821.84
		INTERNAL REVENUE SERVICE Total									13,177.20	0.00	1,821.84
		MASSACHUSETTS DEPARTMENT OF REVENUE	AG0245	Corporate Matters/Contracts	00099	OTH	00235				3,629.70	0.00	0.00
		MASSACHUSETTS DEPARTMENT OF REVENUE Total									3,629.70	0.00	0.00
		RUSSELL R JOHNSON III	AG0236	AGC General Litigation	00036	DIST	00100				373.09	63.43	309.66
		RUSSELL R JOHNSON III Total									373.09	63.43	309.66
National Grid USA Total											17,179.99	63.43	2,131.50
Narragansett Gas Company	00048	CAPITAL RECORDS MANAGEMENT INC	AG0245	Corporate Matters/Contracts	00099	OTH	00235				1,046.21	0.00	0.00
			AG0275	U.K. Insurance-Liability	00099	OTH	00235				137.92	0.00	0.00
		CAPITAL RECORDS MANAGEMENT INC Total									1,184.13	0.00	0.00
		IRON MOUNTAIN OFF-SITE	AG0245	Corporate Matters/Contracts	00099	OTH	00235				785.59	0.00	0.00
		IRON MOUNTAIN OFF-SITE Total									785.59	0.00	0.00
		IRON MOUNTAIN RECORDS MANAGEMENT	AG0238	Information Records Managemen	00099	OTH	00235				922.60	0.00	0.00
			AG0245	Corporate Matters/Contracts	00099	OTH	00235				1,172.70	0.00	0.00
		IRON MOUNTAIN RECORDS MANAGEMENT Total									2,095.30	0.00	0.00
Narragansett Gas Company Total											4,065.02	0.00	0.00
New England Power Company	00010	ALSTON & BIRD LLP	AG0255	Regulatory Legal Services	00099	OTH	00236	353.62	32.27	157.55			
		ALSTON & BIRD LLP Total						353.62	32.27	157.55			
		PRO UNLIMITED INC	AG0245	Corporate Matters/Contracts	00099	OTH	00235				7,309.34	0.00	0.00
							00236				321.13	29.30	143.07

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								Historic Test Year Data					
								Ending Sept. 30, 2008			Ending Sept. 30, 2009		
Originating Business Unit Desc	**Orig Business Unit**	**Vendor**	**Activity**	**Activity Descr**	**Business Unit**	**Segment**	**Billing Pool**	**Sum of Total Payables $**	**Sum of Total Payables Gas**	**Sum of Total Electric**	**Sum of Total Payables $**	**Sum of Total Payables Gas**	**Sum of Total Electric**
			AG0255	Regulatory Legal Services	00099	OTH	00235				1,095.06	0.00	0.00
		PRO UNLIMITED INC Total									8,725.53	29.30	143.07
New England Power Company Total								353.62	32.27	157.55	8,725.53	29.30	143.07
KeySpan Corporate Services LLC	00431	CULLEN AND DYKMAN	923001	A&G-Outside Services Employed	00036	DIST					287,641.38	0.00	287,641.38
						GAS					64,094.37	64,094.37	0.00
						TRAN					43,039.29	0.00	43,039.29
		CULLEN AND DYKMAN Total									394,775.04	64,094.37	330,680.67
KeySpan Corporate Services LLC Total											394,775.04	64,094.37	330,680.67
Grand Total								7,669,744.66	859,249.14	6,090,176.99	8,988,043.17	1,111,987.15	7,063,230.23

Date of Request: March 16, 2010
Due Date: March 26, 2010

Request No. AJR-7
NMPC Req. No. NM 271 DPS 149

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Aric Rider

TO: Infrastructure and Operations Panel

Request

A. Reference IOP Testimony page 180 of 266, line 20. The Company states that it oversees the operation and maintenance of 55 occupied locations – a main office, six specialty/non-operating sites, and 48 operating sites. Please quantify the number of sites the Company plans to oversee in FY 11, FY 12, FY 13 and FY 14, identifying any location changes for each period. In addition, identify the relocated/consolidated sites and the plans for each of these assets.

B. Reference IOP Testimony page 183 of 266, lines 10-11. Please provide the actual historic levels of baseline capital expenditures for FY 06, FY 07, FY 08, FY 09 and FY 10. Identify the period of time used to develop the Company's forecast baseline capital expenditures.

C. Reference IOP Testimony page 197, lines 1-3. Provide the work papers that show how the Company is fairly assessing the Reservoir Woods lease allocation costs to all of the businesses that are run from that facility.

D. Reference IOP Testimony page 197, lines 1-3. What is the aggregated level of lease costs associated with the Reservoir Woods facility that is currently recovered from customers served by all National Grid owned companies?

E. Reference IOP Testimony page 197, lines 1-3. What functions are conducted from Niagara Mohawk facilities that benefit National Grid businesses outside of the Niagara Mohawk service territory, and how are the benefits reflected in the rate filing?

F. Reference IOP Testimony page 197, lines 13-20, and page 198, lines 1-2. Please provide the actual Fleet Service capital expenditures for FY 06, FY 07, FY 08, FY 09 and FY 10.

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G. Reference IOP Testimony page 197, lines 13-20, and page 198 lines 1-2. Please provide the budgeted Fleet Service capital expenditures for FY 06, FY 07, FY 08, FY 09 and FY 10.

H. Reference Exhibit ___(RRP-2) Schedule 45 Sheet 1 of 1, Row 14 – Facilities Rent Forecast. Please explain the $3,496 normalization adjustment.

I. Reference Exhibit ___(RRP-2) Schedule 45 Sheet 1 of 1 Rows 14, 18 & 46. Please explain the rate year increases.

Where applicable in responding to questions A through I above, provide the response in fully accessible formats without restrictions; i.e., not pdf files, but excel or whatever program was used to provide the response.

Response:

A. The Company's Property Services group currently oversees 55 facilities. In 2011, it intends to oversee 53 facilities, and 51 facilities in 2012. The Company proposes to close its locations at Troy (two locations), Glenmont, Saratoga-Federal Street, Syracuse (Beacon North), and Tonawanda. In addition, the Company will add a small crew location in the Troy area to ensure adequate response times are maintained. Further, the Company will not renew its lease of the "E" building at the Syracuse Office Complex (SOC) and has closed and will not renew the lease of its Star Lake, NY site. Both buildings are now vacant and retirements are reflected in Exhibit __ (IOP-5).

B. The Company's baseline capital spend for facilities is as follows:

i. FY 2006 $2,957,542
ii. FY 2007 $4,157,129
iii. FY 2008 $5,159,937
iv. FY 2009 $6,668,866
v. FY 2010 $5,223,298 (to date of the response)

The Company utilized four years of data and applied a multiplier for FY11 through FY14 since it is expected that a lower level of baseline spend will be required due to the large construction projects that will be taking place at the SOC, North Albany and the Buffalo area. Please note these are fiscal year figures as requested whereas the figures in the testimony are calendar year.

C. Attachment 1 (AJR-7_Attach 1_Reservoir Woods Sq Ft Summary With Co.xls) and Attachment 2 (AJR-7_Attach 2_ Reservoir Woods Seating Chart.pdf) are the underlying work papers developed by Property Services for Bill Pool 603 which allocates Reservoir Woods Facilities related costs including its lease expense. Attachment 1 details the specific occupancy to allow development of Bill Pool 603. Attachment 2 depicts the allocated space by department used to populate the excel table in Attachment 1.

D. As shown in Workpaper 5 of Exhibit __(RRP-2), Schedule 8, Sheet 1, column (e) (Book 16, page 178, column (e), line 32), the estimated CY11 aggregate costs of the Reservoir Woods facility is estimated to be $17,713,648 allocated using bill pool 603 to both operating companies and non-operating companies. As the facility has only been is service for nine months, the costs have only been explicitly included in six of the operating companies' revenue requirements filings (Massachusetts Electric, Nantucket Electric, Narragansett Electric, New England Power, EnergyNorth Gas and Niagara Mohawk electric). The remaining operating companies are implicitly recovering these costs in current rates.

E. Functions conducted from Niagara Mohawk facilities that benefit other National Grid businesses include Accounts Payable, Investment Recovery, Human Resources, aircraft transportation, credit and collections, customer service, consumer advocacy and others. Facility costs incurred in support of these functions are allocated to other companies in the form of inter-company rent charges. The Rate filing reflects facility costs to Niagara Mohawk net of any allocation out to other National Grid entities.

F. Actual Fleet Services capital expenditures for FY06 through FY10 are provided below.

	2006	2007	2008	2009	2010
Fleet NY - Co 36	$240,375	$192,341	$225,736	$162,523	$567,604

(generally consists of shop tools & equipment)

G. Fleet Services capital budgets for FY06 through FY10 are provided below.

	2006	2007	2008	2009	2010
Fleet NY - Co 36	$ 238,000	$ 238,000	$ 238,000	$ 238,000	$ 430,000

(generally consists of shop tools & equipment)

H. The $3,496 normalization adjustment is the net of two adjustments: one to annualize the amount of rent expense recorded for the Reservoir Woods facility in the test year, and a second to remove rent expense related to the Sacandaga Reservoir. These represent an increase to test year rent expense of $3,952 and a decrease of test year rent expense of $456, respectively. The books of the Company contained only five months of rent expense for Reservoir Woods (May 2009 – September 2009), and therefore an annualizing adjustment was needed to normalize the test year. Please refer to Exhibit__(RRP-10), Schedule 8, Workpaper 6 for the calculation of the normalization entry, as well as the response to DKS-3 Part 3 which provides further support of the annual lease obligation. The Company has taken the position that as of July 2009, it is no longer obligated to pay the annual operating & maintenance expenses of the Sacandaga Reservoir, and therefore the amount of $456 recorded in the test year was removed as a normalization adjustment.

I. <u>Row 14 (Facilities Rent forecast) (amounts in 000s)</u>
Please refer to Exhibit ___(RRP-2), Schedule 8, Sheets 8 & 9.

RY 2011 ($3,306) - The decrease in rent expense in RY 2011 over the adjusted test year is due to the expiration of lease arrangements at Beacon North ($1,153) and the SOC E Building ($1,348) during Calendar Year 2011. The Company has decided to let these leases terminate due to Facilities consolidation initiatives.
RY 2012 ($255) – The decrease in RY 2012 rent expense over RY 2011 rent expense represents the expiration of the Beacon North lease, as there are two months of rent expense included in RY 2011 and none in RY 2012.
RY 2013 ($229) – The decrease in RY 2013 rent expense over RY 2012 rent expense represents the expiration of lease arrangements at Saratoga Wiebel and the SOC E Building Parking facility ($83 and $111, respectively). The Company has decided to let these leases terminate due to Facilities consolidation initiatives.

Row 18 (IT Rent forecast) (amounts in 000s)
Please refer to Exhibit___(RRP_2), Schedule 8, Sheets 10 & 11.
RY 2011 $1,935 – The increase in RY 2011 rent expense over the test year is due to the net effect of the winding down of existing software lease agreements and new leased software assets coming online in the Rate Year. Existing lease expirations represent a decrease in expense of ($2,944) over the test year, the largest portion being the PeopleSoft ERP system ($1,991). New leased software represent an increase to rent expense of $4,894, the largest projects being the Customer Systems Agent Desktop $688, Datacenter Rationalization $453, IVR Phase 2 $603, and Transformation KPIs $432.
RY 2012 $5,447 – The increase in RY 2012 rent expense over the RY 2011 expense represents further software projects placed into service in RY 2012, the largest being the US SAP Back office $3,798. There is only a relatively small decrease in RY 2012 for existing project leases terminating ($431).
RY 2013 $4,723 – The increase in RY 2013 rent expense over the RY 2012 expense represents the net effect of the Field Force Automation (FFA) lease terminating and further software projects placed into service. FFA will be fully amortized as of February 2013, resulting in a decrease in rent expense of $2,768. The largest projects placed into service during RY 2013 are Distribution/Outage Management System $2,354 and the Electric Distribution Legacy Grid Mobile Expansion $1,316. In addition, RY 2013 contains a full year of SAP Back Office lease charges versus nine months in RY 2011, an increase of $1,454.

Row 46 (Transmission Rent forecast) (amounts in 000s)
Please refer to Exhibit___(RRP-2), Schedule 8, Sheets 12 & 13
RY 2011 $1,266 – The increase in RY 2011 rent expense over the test year represents annual increases in contractual lease payments for the Volney –Marcy Transmission line.
RY 2012 $229 – The increase in RY 2012 rent expense over the RY 2011 expense represents the annual increase in contractual lease payments for the Volney –Marcy Transmission line.
RY 2013 $250 - The increase in RY 2013 rent expense over the RY 2012 expense represents the annual increase in contractual lease payments for the Volney –Marcy Transmission line.

Name of Respondent: Date of Reply:

Michael E. Guerin
James M. Molloy

March 29, 2010

Form 103

AJR-7
Attachment 1

National Grid- Reservoir Woods

GROUP	% VALUE FROM TOTAL BUILDING	Segmentation Methodology	Segmentation % DIST	GAS	TRAN	SDEV	NREG	INTE	GEN	OTH	Total	Segmentation $ (through 12/31/08) DIST	GAS	TRAN	SDEV	NREG	INTE	GEN	OTH	Total
FL1																				
Gas Supply Planning	0.3%	100% GAS	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%									
Mergers & Acquisitions	0.8%	FY09 Segment %	0.0%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.1%	0.8%	54	30	6	962	-	-	4	203	1,259
Reg and Gen Council	6.4%	FY09 Segment %	2.4%	2.4%	0.5%	0.0%	0.3%	0.0%	0.4%	0.4%	6.4%	11,993	11,740	2,566	6	1,275	25	1,633	1,990	31,428
Shared Prop/Office Svcs	3.9%	FY09 Segment %	2.2%	1.3%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%	38,787	23,950	6,391	-	(40)	56	698	97	70,939
Human Resources	3.4%	FY09 Segment %	1.8%	1.2%	0.3%	0.0%	0.0%	0.0%	0.1%	0.0%	3.4%	95,689	62,180	14,157	273	1,423	453	6,769	(1,017)	179,927
Customer and Markets	7.3%	FY09 Segment %	4.0%	3.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	7.3%	131,061	96,953	885	-	4,448	51	1,127	627	235,152
Corporate Affairs	1.5%	FY09 Segment %	0.6%	0.5%	0.1%	0.0%	0.1%	0.0%	0.1%	0.1%	1.5%	6,883	5,371	797	-	660	10	901	1,297	15,919
Internal Audit	0.9%	FY09 Segment %	0.4%	0.4%	0.0%	0.0%	0.1%	0.0%	0.1%	0.0%	0.9%	1,549	1,440	134	-	200	2	227	184	3,736
TOTAL	24.4%		11.6%	9.0%	1.3%	0.6%	0.6%	0.0%	0.7%	0.7%	24.4%									
FL2																				
Transmission																				
	7.1%	100% TRAN	0.0%	0.0%	7.1%	0.0%	0.0%	0.0%	0.0%	0.0%	7.1%									
	0.4%	100% TRAN	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%									
	0.8%	100% TRAN	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%									
	0.1%	100% TRAN	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%									
	1.9%	100% TRAN	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%									
	0.2%	100% TRAN	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%									
	10.6%		0.0%	0.0%	10.6%	0.0%	0.0%	0.0%	0.0%	0.0%	10.6%									
IS																				
	0.3%	FY09 Segment %	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	59,785	47,868	6,975	-	1,988	257	6,743	5,465	129,081
	1.1%	FY09 Segment %	0.5%	0.4%	0.1%	0.0%	0.0%	0.0%	0.1%	0.0%	1.1%									
	3.3%	FY09 Segment %	1.5%	1.2%	0.2%	0.0%	0.1%	0.0%	0.2%	0.1%	3.3%									
	0.2%	FY09 Segment %	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%									
	0.5%	FY09 Segment %	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%									
	0.1%	FY09 Segment %	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%									
	2.5%	FY09 Segment %	1.2%	0.9%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	2.5%									
	0.5%	FY09 Segment %	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%									
	0.2%	FY09 Segment %	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%									
	8.8%	FY09 Segment %	4.1%	3.3%	0.6%	0.0%	0.1%	0.0%	0.5%	0.4%	8.8%									
Finance																				
	0.7%	FY09 Segment %	0.4%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	77,876	24,712	18,235	51	1,481	253	3,276	2,154	128,038
	1.3%	FY09 Segment %	0.8%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%									
	0.8%	FY09 Segment %	0.5%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%									
	0.1%	FY09 Segment %	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%									
	0.4%	FY09 Segment %	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%									
	0.1%	FY09 Segment %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%									
	0.5%	FY09 Segment %	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%									
	0.1%	FY09 Segment %	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%									
	4.0%	FY09 Segment %	2.4%	0.8%	0.6%	0.0%	0.0%	0.0%	0.1%	0.1%	4.0%									
Gas Distribution																				
	1.1%	100% GAS	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%									
	0.7%	100% GAS	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%									
	1.2%	100% GAS	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%									
	0.2%	100% GAS	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%									
	6.6%	100% GAS	0.0%	6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%									
	4.0%	100% GAS	0.0%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%									
	0.1%	100% GAS	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%									
	0.3%	100% GAS	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%									
	14.1%	100% GAS	0.0%	14.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.1%									
TOTAL	37.6%		6.5%	18.2%	11.5%	0.0%	0.2%	0.0%	0.6%	0.4%	37.6%									
FL3																				
Electric Distribution																				
	14.5%	100% DIST	14.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.5%									
	1.9%	100% DIST	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%									
	1.5%	100% DIST	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%									
	0.2%	100% DIST	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%									
	0.8%	100% DIST	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%									
	1.4%	100% DIST	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%									
	0.2%	100% DIST	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%									
	6.8%	100% DIST	6.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%									
	0.7%	100% DIST	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%									
	2.0%	100% DIST	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%									
	1.4%	100% DIST	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%									
	1.4%	100% DIST	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%									
	2.0%	100% DIST	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%									

GROUP	% VALUE FROM TOTAL BUILDING	Segmentation Methodology	DIST	GAS	TRAN	BDEV	NREG	INTE	GEN	OTH	Total
	34.6%	100% DIST	34.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	34.6%
SHES	1.8%	FY09 Segment %	1.1%	0.6%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	1.8%
Supply Chain	1.2%	FY09 Segment %	0.7%	0.4%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	1.2%
Tom King	0.3%	100% DIST	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
TOTAL	38.1%		36.7%	1.0%	0.1%	0.0%	0.0%	0.0%	0.3%	0.1%	38.1%

DIST	GAS	TRAN	BDEV	NREG	INTE	GEN	OTH	Total
24,435	13,376	768	-	214	8	3,707	844	43,352
6,850	4,981	813		95	164	844	383	14,110
								-

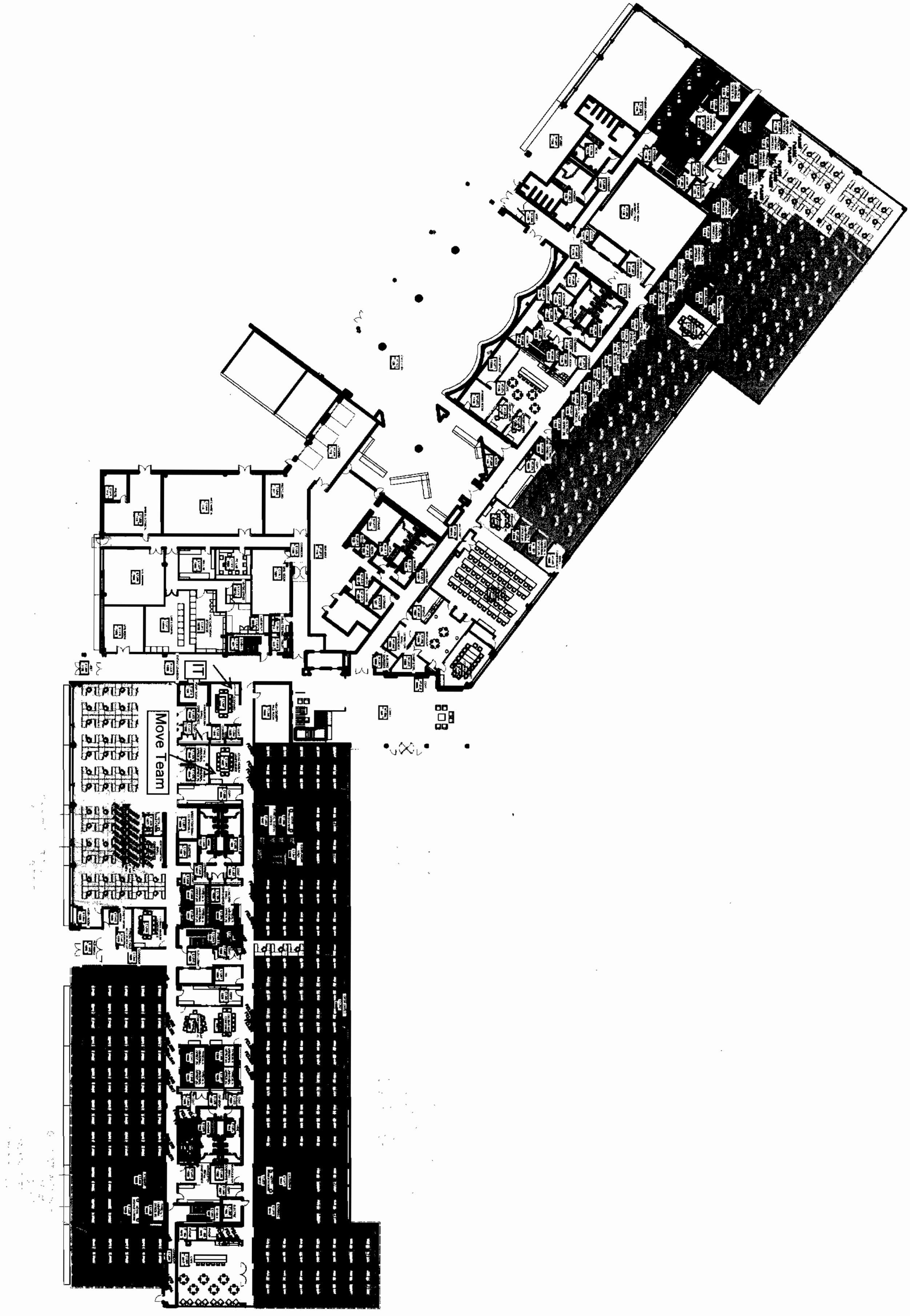
BUILDING TOTALS

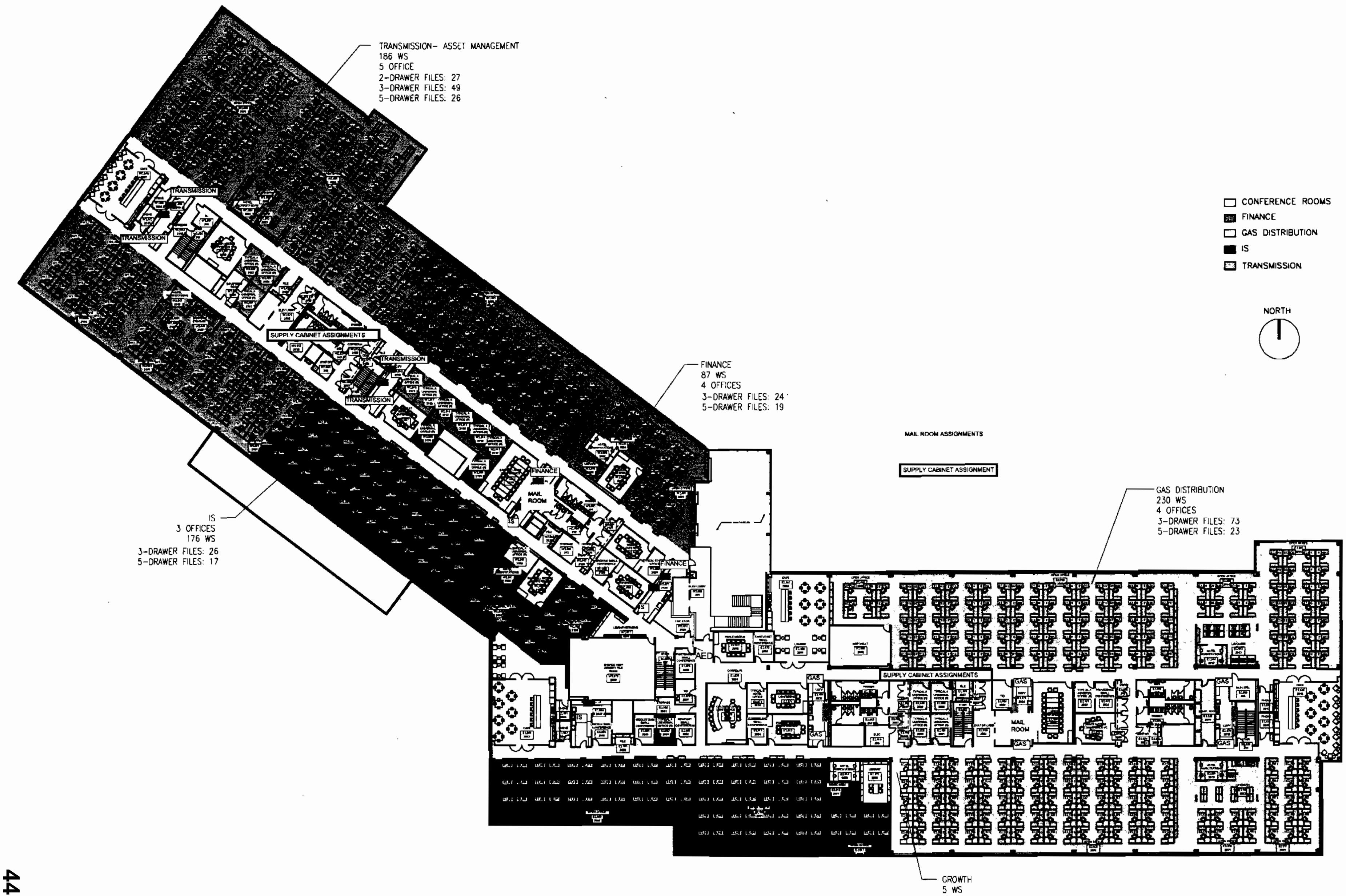
		DIST	GAS	TRAN	BDEV	NREG	INTE	GEN	OTH	Total
TOTAL	100.0%	54.8%	28.2%	12.9%	0.6%	0.7%	0.0%	1.6%	1.2%	100.0%

Bill Pool 00382	00004	Nantucket Electric	0.1240%
Bill Pool 00382	00005	Massachusetts Electric	15.5849%
Bill Pool 00382	00006	NEHTEC-MA Hydro	0.1618%
Bill Pool 00382	00008	NEHTC-NH Hydro	0.4271%
Bill Pool 00382	00010	New England Power	2.3887%
Bill Pool 00382	00020	NEET	0.0152%
Bill Pool 00382	00021	NGUSA Transmission	0.0015%
Bill Pool 00382	00036	Niagara Mohawk Power	31.5542%
Bill Pool 00382	00041	Granite State Electric	0.4444%
Bill Pool 00382	00048	Narragansett Gas	3.4887%
Bill Pool 00382	00049	Narragansett Electric	5.3206%
Bill Pool 00382	00070	Wayfinder	0.0011%
Bill Pool 00382	00071	VAMCO	0.0000%
Bill Pool 00382	01401	Boston Gas Company	7.6577%
Bill Pool 00382	01403	Colonial Lowell Division	1.2588%
Bill Pool 00382	01406	EnergyNorth Company	0.6767%
Bill Pool 00382	01434	Keyspan Electric Services LLC	8.0352%
Bill Pool 00382	01435	Keyspan Generation Services LLC	5.0138%
Bill Pool 00382	01436	Keyspan Energy Development	0.0780%
Bill Pool 00382	01437	Keyspan Energy Delivery LI	5.8146%
Bill Pool 00382	01438	Keyspan Energy Delivery NY	11.3395%
Bill Pool 00382	01442	Keyspan Ravenswood Services, LLC	0.0000%
Bill Pool 00382	01446	Keyspan Glenwood Energy Center LLC	0.1062%
Bill Pool 00382	01448	Keyspan Port Jefferson Energy Center LLC	0.1101%
Bill Pool 00382	01456	Keyspan Energy Supply Inc	0.0000%
Bill Pool 00382	01459	Keyspan Services Inc	0.0065%
Bill Pool 00382	01471	Seneca Upshur Petroleum	0.3507%
Bill Pool 00382	01563	Keyspan E&P Joint Venture 50%	0.0400%
			100.0000%

Company totals per Billing Pool 00382 were applied to the segment totals shown above to produce company total by segment shown below:

		DIST	GAS	TRAN	BDEV	NREG	INTE	GEN	OTH	Total
00004	Nantucket Electric	0.0679%	0.0349%	0.0160%	0.0006%	0.0009%	0.0001%	0.0019%	0.0015%	0.1240%
00005	Massachusetts Electric	8.5351%	4.3873%	2.0101%	0.1005%	0.1139%	0.0071%	0.2415%	0.1893%	15.5849%
00006	NEHTEC-MA Hydro	0.0886%	0.0456%	0.0209%	0.0010%	0.0012%	0.0001%	0.0025%	0.0020%	0.1618%
00008	NEHTC-NH Hydro	0.2339%	0.1202%	0.0551%	0.0028%	0.0031%	0.0002%	0.0066%	0.0052%	0.4271%
00010	New England Power	1.3082%	0.6724%	0.3081%	0.0154%	0.0175%	0.0011%	0.0370%	0.0290%	2.3887%
00020	NEET	0.0083%	0.0043%	0.0020%	0.0001%	0.0001%	0.0000%	0.0002%	0.0002%	0.0152%
00021	NGUSA Transmission	0.0008%	0.0004%	0.0002%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0015%
00036	Niagara Mohawk Power	17.2807%	8.8826%	4.0697%	0.2035%	0.2306%	0.0144%	0.4890%	0.3834%	31.5542%
00041	Granite State Electric	0.2434%	0.1251%	0.0573%	0.0029%	0.0032%	0.0002%	0.0069%	0.0054%	0.4444%
00048	Narragansett Gas	1.9106%	0.9821%	0.4500%	0.0225%	0.0255%	0.0016%	0.0541%	0.0424%	3.4887%
00049	Narragansett Electric	2.9138%	1.4978%	0.6862%	0.0343%	0.0389%	0.0024%	0.0825%	0.0646%	5.3206%
00070	Wayfinder	0.0006%	0.0003%	0.0001%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0011%
00071	VAMCO	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
01401	Boston Gas Company	4.1937%	2.1557%	0.9877%	0.0494%	0.0560%	0.0035%	0.1187%	0.0930%	7.6577%
01403	Colonial Lowell Division	0.6894%	-0.3544%	0.1624%	0.0081%	0.0092%	0.0006%	0.0195%	0.0153%	1.2588%
01406	EnergyNorth Company	0.3706%	0.1905%	0.0873%	0.0044%	0.0049%	0.0003%	0.0105%	0.0082%	0.6767%
01434	Keyspan Electric Services LLC	4.4005%	2.2620%	1.0363%	0.0518%	0.0587%	0.0037%	0.1245%	0.0976%	8.0352%
01435	Keyspan Generation Services LLC	2.7458%	1.4114%	0.6467%	0.0323%	0.0366%	0.0023%	0.0777%	0.0609%	5.0138%
01436	Keyspan Energy Development	0.0427%	0.0220%	0.0101%	0.0005%	0.0006%	0.0000%	0.0012%	0.0009%	0.0780%
01437	Keyspan Energy Delivery LI	3.1844%	1.6369%	0.7499%	0.0375%	0.0425%	0.0027%	0.0901%	0.0706%	5.8146%
01438	Keyspan Energy Delivery NY	6.2101%	3.1922%	1.4625%	0.0731%	0.0829%	0.0052%	0.1757%	0.1378%	11.3395%
01442	Keyspan Ravenswood Services, LLC	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
01446	Keyspan Glenwood Energy Center LLC	0.0581%	0.0299%	0.0137%	0.0007%	0.0008%	0.0000%	0.0016%	0.0013%	0.1062%
01448	Keyspan Port Jefferson Energy Center LLC	0.0603%	0.0310%	0.0142%	0.0007%	0.0008%	0.0001%	0.0017%	0.0013%	0.1101%
01456	Keyspan Energy Supply Inc	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
01459	Keyspan Services Inc	0.0036%	0.0018%	0.0008%	0.0000%	0.0000%	0.0000%	0.0001%	0.0001%	0.0065%
01471	Seneca Upshur Petroleum	0.1920%	0.0987%	0.0452%	0.0023%	0.0026%	0.0002%	0.0054%	0.0043%	0.3507%
01563	Keyspan E&P Joint Venture 50%	0.0219%	0.0113%	0.0052%	0.0003%	0.0003%	0.0000%	0.0006%	0.0005%	0.0400%
		54.7660%	28.1509%	12.8976%	0.6451%	0.7310%	0.0457%	1.5498%	1.2149%	100.0000%


Move Team



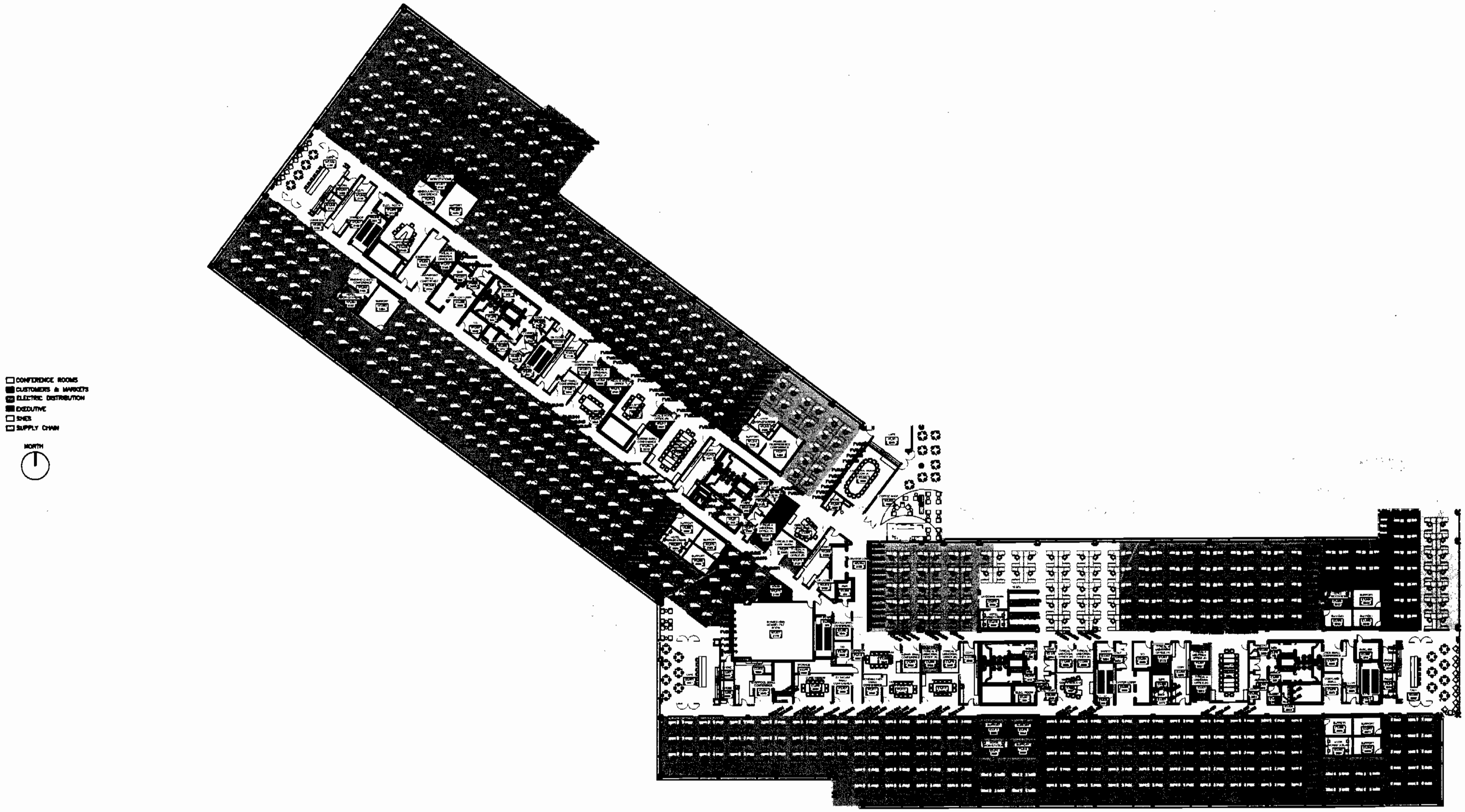
Second Floor Plan, NTS

National Grid NE Main Office

April 22, 2009

nationalgrid

SASAKI


CONFERENCE ROOMS
CUSTOMERS & MARKETS
ELECTRIC DISTRIBUTION
EXECUTIVE
SHES
SUPPLY CHAIN
NORTH

Date of Request: March 16, 2010
Due Date: March 26, 2010

Request No. DAG-10
NMPC Req. No. NM 273 DPS 151

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Accounting Services Expense

1. Please provide both the HY actual amount for HYEs 9/20/2009, 9/30/2008, 9/30/2007 and 9/30/2006, and also the RYs' forecasted amounts for accounting services expense and identify where those stated amounts can be found in the Company's exhibits and workpapers. If the amounts cannot be explicitly derived from the exhibits and workpapers, please provide a list of charges by expense type, originating business units, direct and indirect charges, and activity number with activity description, along with vendor names (see the Company's response to DAG-15 (NM-145), in Case 08-G-0609 if this question cannot be responded to in the exact format asked. As an alternative, a response similar to the Company response to DAG-15 could be provided and updated for historic years 2006 through 2009).

2. Please (a) provide all normalizing adjustments the company made to HY accounting services expense; and (b) explain and provide a copy of the analysis the Company undertook to determine the actual HY accounting services expense that needed to be normalized, in forecasting RY levels.

3. If the answer to question 2 above is, "There are no normalizing adjustments made to the HY," please explain and provide a copy of the analysis the Company undertook to determine the actual HY accounting services expense was reasonable and included no non-recurring items, in forecasting the RY.

Response:

1. In accordance with regulatory policy, the Company's O&M expense exhibit RRP-2 is presented by functional group, subdivided between Operation and Maintenance, with separate schedules for different cost elements (i.e. expense types). The Revenue Requirement Panel testimony describes the exhibit in further detail. Accounting Services is not defined by a single expense type (cost element) in the Company's general ledger, and therefore is not presented explicitly in the Company's exhibits or workpapers.

Please see the following attachments for requested information regarding Accounting Services costs, as an update to the Company's response to DAG-15 (NM-145) in Case 08-G-0609:

Attachment 1 – the Rate Year ended December 31, 2011 and Historical Test Year ended September 30, 2009
Attachment 2 – the twelve months ended September 30, 2008
Attachment 3 - the twelve months ended September 30, 2007
Attachment 4 - the twelve months ended September 30, 2006

Please note that due to organizational changes in the businesses, the departments reporting through the Controller have changed since Case 08-G-0609. Those departments consist of the following:

Controller		Controller	11000
		Acctg Services Corp Overheads	11999
	Accounting Services	Acctg Services-NE	11200
		Acctg Services-NY	11250
		Financial Reporting-NY (Inactive 11/8/05)	11450
		Non-Income Tax	11600
		Fin Reporting Asst Controller	92015
		Financial Processing	92016
		Tax	92017
		Accounting Services	92018
		VP Financial Planning	92020
		VP & Controller NE	92168
		KeySpan Integration	92527
		KETS Backoffice	92856
		KSP Backoffice	92857
		Financial Services	92519
		Accounting	92521
	Pension Accounting	Pension Accounting	11400

2. As explained above in Part 1, the Company presented O&M expenses for the Historical Year, Historical Year Normalizing Adjustments and Rate Year Adjustments by expense type, not by organization or department (i.e. "Accounting Services"). For example, Historical Year Adjustments were made to various expense types to remove non-recurring New England and KeySpan integration costs. Exhibit RRP-10, Workpaper to RRP-2, Schedule 1, Workpaper 5 shows how these costs were removed from Expense Type 100 (supportive of RRP-2), regardless of what department was charged. Please refer to Attachment 1, Sheet 2 and Attachment 2, Sheet 1 for normalization adjustments

made to the Accounting Services analyses for the HTY and the twelve months ended September 30, 2008.

3. The Company's approach to the review of Historical Year data was to organize it principally by expense type. For each expense type, then Company queried Historical Year (HY) data generally including information deemed relevant to the specific expense type (i.e. Company, Department, Activity, Segment, Bill Pool, Project, etc). Exhibit RRP-10, Workpaper to RRP-2, Schedule 1, Workpapesr 1 – 7 and Exhibit RRP-10, Workpaper to RRP-2, Schedule 2, Workpapers 1 – 8 are the result of this work. As described in the Company's response to Part 1.a and .b of IR DPS 138 DAG-4 on March 23, 2009, an analysis was done on all expense types by project to analyze year over year variance and scrutinize projects for purposes of normalizing the historical test year. In addition, finance representatives from lines of business and shared service groups met regularly with regulatory personnel as part of the RCS process, described in IR DAG-4, Part 9, to review year on year variance analysis between historical test year and forecasted rate year. These individuals were provided a high-level functional profile of the HY costs and asked to review this data and to address the following:

- Identify one time costs in the HY that may not be recurring in future years
- Review prior period costs booked in the HY
- Identify any corrections, transfers, adjustments etc.
- Identify any new major initiatives (not in HY) excluding NE Gas and KeySpan Costs to Achieve and Synergy Savings that would be incurred in Calendar Years 2011 through 2013
- Provide detailed descriptions of historic year costs and the impact on rate year.

As a result of these processes, there were no one-time costs identified specific to the Controller/Accounting Services group, aside from NEG & KeySpan Integration costs.

Name of Respondent:	Date of Reply:
Melissa Little	March 29, 2010

Consultants and Contractors Charged to Controller/Accounting Services

Bus Unit	Ledger Source	RY 2013	RY 2012	RY 2011	HTY 9/30/09	12 mos 9/30/08	12 mos 9/30/07	12 mos 9/30/06
	Inflation	1.9000%	1.8000%	3.2146%				
99	AP (see List)	337,064	330,779	324,930	314,810	185,445	477,486	164,567
36	AP (see List)	64,137	62,941	61,828	59,903	197,390	174,177	111,807
99	On Line JE	1,842,516	1,808,161	1,776,190	1,720,870	731,871	1,362,169	174,543
36	On Line JE	504,137	494,737	485,989	470,853	1,065	26,384	542,690
	Total	2,821,980	2,734,090	2,648,937	2,566,436	1,115,770	2,040,216	993,607
	Add back: Out of period adjustment					331,122		
	Add back: Presentation reclass					183,316		
	Adjusted total	2,821,980	2,734,090	2,648,937	2,566,436	1,630,208	2,040,216	993,607

Date of Request: March 16, 2010
Due Date: March 26, 2010

Request No. DAG-11
NMPC Req. No. NM 274 DPS 152

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Capital, Expense, Total Labor for FYE 3/09, HYE 9/09 and FYE 3/2010.

1. Using the methodology, as documented in the Company's supplemental response to I/R #PSC-276 in C. 01-M-0075 dated 4/2/07, and in a format similar to that provided in Attachment 3 of this supplemental response, please provide the updated information as it would apply to (a) Fiscal Year Ended (FYE) 3/09; (b) Historic Year Ended (HYE) 9/09; and (c) FYE 3/2010. Provide source information for the amounts provided.

Response:
Part 1a & b. Please see attached file DAG-11 Attachment 1 (Fringe Cap Rate) sheet 1 for the fringe benefit capitalization rate calculated using the methodology consistent with I/R #PSC-276 in C. 01-M-0075 dated 4/2/07 as requested. The Company is also including in attachment 1, sheet 1 the fringe benefit capitalization rate calculation methodology and result consistent with our accounting system and applied in our rate filing. The payroll data used in the calculations is provided in sheet 2 of attachment 1.

Part 1c. The calculation provided in Part 1a & b will be updated for fiscal year ending March 31, 2010 and provided to staff within five days from the year-end closing of The Company's books of record.

Name of Respondent:
Mark Stiner

Date of Reply:
3/26/2010

Niagara Mohawk Power Corporation
Fringe Benefit Capitalization

		(a)	(b)	(c)	(d)	(e)	(f)
		Fiscal Year March 2009			Historic Test Year September 2009		
		NG Accounting Method	PSC 276 Method		NG Accounting Method	PSC-276 Method	NG Accounting Method (Total Non-expense)
1 Total Payroll		332,512,359	332,512,359		327,120,416	327,120,416	327,120,416
2 3rd Party			(1,638,404)			(914,453)	
3 Cost of Removal			(9,379,052)			(9,722,840)	
4 Other			0			(233,336)	
5 Associated			(6,896,108)			(7,603,193)	
6 Payroll Accrual							
7 Incremental Overtime		(24,643,249)			(22,382,713)		(22,382,713)
8 Less Transportation Clearing Labor charged to O&M (66%)			(8,494,618)			(8,541,388)	(8,351,798)
9 Less Stores Clearing Labor charged to O&M (19%)			(4,394,356)			(4,300,150)	(4,185,742)
10 Less: Non- Productive Time		(48,534,934)	(5,266,040)		(48,230,546)	(5,608,517)	(48,230,546)
11 NET PRODUCTIVE LABOR		259,334,175	296,443,781		256,507,158	290,196,540	243,969,618
Fringe Benefits:							
12 Thrift Plan (Expense Type B07)	6,590,523	2.54%	2.22%	6,617,118	2.58%	2.28%	2.71%
13 FAS 112 (Expense Type B02)	4,304,433	1.66%	1.45%	2,980,544	1.16%	1.03%	1.22%
14 Group Insurance (Expense Type B04)	2,236,299	0.86%	0.75%	1,712,347	0.67%	0.59%	0.70%
15 Medical Care & Prescription Plans (Expense Type B03)	25,418,181	9.80%	8.57%	29,346,650	11.44%	10.11%	12.03%
16 Pension (Expense Type B06)	43,074,304	16.61%	14.53%	45,031,069	17.56%	15.52%	18.46%
17 OPEB (Expense Type B01)	134,690,647	51.94%	45.44%	41,191,253	16.06%	14.19%	16.88%
18 TOTAL FRINGE BENEFITS	216,314,387	**83.41%**	**72.97%**	126,878,981	**49.46%**	**43.72%**	**52.01%**
19 Workers Compensation (Expense Type B08)	3,604,042	1.39%	1.22%	1,729,494	0.67%	0.60%	0.71%
20 Payroll Taxes (Expense Type B09)	25,459,852	9.82%	8.59%	1,061,809	0.41%	0.37%	0.44%
21 Total percentage to be applied to productive Company labor for Payroll Taxes, Fringe Benefits and OPEBs:	245,378,281	**94.62%**	**82.77%**	129,670,284	**50.55%**	**44.68%**	**53.15%**
22 CWIP		68,051,631	73,830,928		69,901,227	69,901,227	69,901,227
23 Time Not Worked			12,619,083			13,143,393	
24 Cost of Removal		8,507,906			8,879,686		8,879,686
25 3rd Party							833,056
26 Associated Company							7,344,464
27 Incremental Overtime						5,396,752	
28 Capital, Associated Company and Billable Projects		76,559,537	86,450,011		78,780,914	88,441,373	86,958,434
29 OPEB/Pension Rates		68.55%	59.97%		33.61%	29.71%	35.34%
30 OPEB/Pension Capitalized		52,479,016	51,840,460		26,481,418	26,277,434	30,732,343
31 Other Benefits Rates		26.07%	22.81%		16.94%	14.97%	17.81%
32 Other Benefits Capitalized		19,960,521	19,717,644		13,344,151	13,241,362	15,486,218
33 Capital percent		29.52%	29.16%		30.71%	30.48%	35.64%

Column Notes

Col's a,b,d, e : Calculate the rate of fringe benefits to be capitalized exclusive of Associated Company and 3rd Party billings.

Col f : Calculates a rate of fringe benefits capitalized and fringe benefits applied to Associated Company and 3rd Party billings. Also, this is the revised rate as indicated in The Company's response to RAV-20 Supplemental Part C on March 16, 2010.

Date of Request: April 22, 2010
Due Date: April 26, 2010

Request No. DAG-11 SUPP
NMPC Req. No. NM 274 DPS 152

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Capital, Expense, Total Labor for FYE 3/09, HYE 9/09 and FYE 3/2010.

1. Using the methodology, as documented in the Company's supplemental response to I/R #PSC-276 in C. 01-M-0075 dated 4/2/07, and in a format similar to that provided in Attachment 3 of this supplemental response, please provide the updated information as it would apply to (a) Fiscal Year Ended (FYE) 3/09; (b) Historic Year Ended (HYE) 9/09; and (c) FYE 3/2010. Provide source information for the amounts provided.

Response:
Part 1c. Please see attached file DAG-11 Supp Attachment 1 (Fringe Cap Rate) sheet 1 for the fringe benefit capitalization rate calculated using the methodology consistent with I/R #PSC-276 in C. 01-M-0075 dated 4/2/07 as requested. The Company is also including in attachment 1, sheet 1 the fringe benefit capitalization rate calculation methodology and result consistent with our accounting system and applied in our rate filing. The payroll data used in the calculations is provided in sheet 2 of attachment 1.

Name of Respondent:
Mark Stiner

Date of Reply:
4/30/2010

Form 103

NIAGARA MOHAWK POWER CORPORATION
NON-PRODUCTIVE TIME, FRINGE BENEFITS and OPEB RATES CALC

			(a)	(b)	(c)
				Fiscal Year March 2010	
			NG Accounting Method	PSC-276 Method	NG Accounting Method (Total Non-expense)
1	Total Payroll		321,626,555	321,626,555	321,626,555
2	3rd Party			(2,988,802)	
3	Cost of Removal			(10,405,427)	
4	Other			0	
5	Associated			(7,940,601)	
6	Payroll Accrual				
7	Incremental Overtime		(18,718,713)		(18,718,713)
8	Less Transportation Clearing Labor charged to O&M (66%)			(8,482,718)	(8,318,097)
9	Less Stores Clearing Labor charged to O&M (19%)			(4,229,309)	(4,121,842)
10	Less: Non- Productive Time		(48,320,889)	(6,009,526)	(48,320,889)
11	**NET PRODUCTIVE LABOR**		254,586,954	281,570,172	242,147,015
	Fringe Benefits:				
12	Thrift Plan (Expense Type B07)	6,498,553	2.55%	2.31%	2.68%
13	FAS 112 (Expense Type B02)	2,583,822	1.01%	0.92%	1.07%
14	Group Insurance (Expense Type B04)	1,296,618	0.51%	0.46%	0.54%
15	Medical Care & Prescription Plans (Expense Type B03)	31,180,307	12.25%	11.07%	12.88%
16	Pension (Expense Type B06)	34,022,655	13.36%	12.08%	14.05%
17	OPEB (Expense Type B01)	48,913,093	19.21%	17.37%	20.20%
18	**TOTAL FRINGE BENEFITS**	124,495,048	**48.90%**	**44.21%**	**51.41%**
19	Workers Compensation (Expense Type B08)	4,017,726	1.58%	1.43%	1.66%
20	Payroll Taxes (Expense Type B09)	1,682,341	0.66%	0.60%	0.69%
21	**Total percentage to be applied to productive Company labor for Payroll Taxes, Fringe Benefits and OPEBs:**	130,195,116	**51.14%**	**46.24%**	**53.77%**
22	CWIP		74,078,909	74,078,909	74,078,909
23	Time Not Worked			14,054,381	
24	Cost of Removal		9,509,212		9,509,212
25	3rd Party				2,213,576
26	Associated Company				7,704,151
27	Incremental Overtime			5,571,507	
28	**Capital, Associated Company and Billable Projects**		83,588,120	93,704,797	93,505,848
29	OPEB/Pension Rates		32.58%	29.45%	34.25%
30	OPEB/Pension Capitalized		27,230,159	27,600,500	32,025,906
31	Other Benefits Rates		18.56%	16.78%	19.52%
32	Other Benefits Capitalized		15,516,591	15,727,623	18,249,356
33	**Capital percent**		32.83%	33.28%	38.62%

Notes

Col's a,b: Calculate the rate of fringe benefits to be capitalized exclusive of Associated Company and 3rd Party billings.
Col c : Calculates a rate of fringe benefits capitalized and fringe benefits applied to Associated Company and 3rd Party billings.

Date of Request: March 16, 2010
Due Date: March 26, 2010

Request No. AAE-17
NMPC Req. No. NM 276 DPS 154

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Allison Esposito

TO: Infrastructure and Operations Panel

Request

1. Please explain the Regional Delivery Ventures (RDV) competitive procurement event process. As part of this explanation, please answer the following questions:

A. In what ways is this similar to or different from a competitive bidding process?
B. How many companies participated in this event?
C. What factors, other than cost, were considered when choosing NEPA?
D. Was NEPA the least expensive option? If not, please list (1) each company that was less expensive than NEPA and (2) NMPC's reasons for not selecting them.

2. Please provide the cost/benefit analysis that shows that the use of the RDV, rather than a traditional competitive bidding process or the process used for the Distribution Alliance Contracts, is beneficial to customers. Please ensure that this analysis includes the gain sharing component of the RDV.

3. Please explain why the gain sharing mechanism included in the RDV was not included as an incentive to reduce costs in the Distribution Alliance Contracts.

4. How will the Company account for NEPA's share of any gain share payments? Will these payments be capitalized as part of the infrastructure investment or expensed as incurred? Fully explain your accounting rationale.

5. As the gain share mechanism rewards NEPA for costs incurred below targets, how does the Company ensure that NEPA is actually cutting costs to achieve these "savings" rather than overestimating their budgeted expenses?

6. Has NEPA been awarded any gain shares thus far – either through the completion of a project or through core team annual cost reviews? Please continue to update this response throughout the course of the rate case proceedings.

7. Please provide the NEPA RDV contract.

Form 103

Response:

1.

A. A competitive procurement process was followed to select the Regional Delivery Ventures (RDVs). Consistent with competitive bidding processes, the Company evaluated bidder qualifications per the Pre-Qualification Questionnaire provided in Attachment 1 of NM 322 DPS 194 JJA-12. Additionally, an assessment of pricing data was completed under the direction of the Company's Procurement department and included the evaluation of pricing comparison sheets for fee, equipment, labor rates, unit rates, core team, and typical projects. The unit rates are used in the development of the project target costs.

   The Procurement Event was conducted in three stages leading to the selection of the optimal partners to form the Regional Delivery Ventures (RDV):

   - Bid Stage 1 - The first stage of the assessment was a desktop assessment of the bid submittals.
   - Bid Stage 2 – The second stage of the assessment process included site visits to verify the findings of the desktop assessment.
   - Bid Stage 3 – In the third stage, the Company conducted workshops to assess the relative performance of potential RDV partners to work together with the Company in a collaborative environment.

B. Expressions of Interest were received from thirty individual companies to the Company's February 29, 2008 Request for Information (RFI). Six groups of companies participated in the Company's July 1, 2008 Request for Proposal (RFP). Northeast Power Alliance (NEPA) was the successful bidder for the Upstate New York RDV.

C. In addition to bidder qualifications and pricing, the selection process included an assessment of bidders' performance and experience in the following areas:

   - Safety, Environment and Quality
   - Commercial
   - Continuous Improvement
   - Resource Assurance, Program Management and Resource Planning, Construction, Engineering and Design, Leadership and People
   - Cultural Fit (collaboration, relationships, objectives)

D. NEPA was evaluated as the least expensive option for the New York RDV award.

2. As described in the testimony of the Infrastructure and Operations Panel at pp. 152-155, the collaborative RDV model has been used to deliver value over the traditional project-by-project bidding process, including improved contract oversight, scalability, and delivery efficiencies necessary to deliver the capital investment plan. For example, the employment of a single long-term service provider in a geographic region reduces demobilization/mobilization costs, provides resource continuity, and allows for the optimization of specialty equipment.

During the competitive procurement event, a total cost analysis was performed to evaluate the cost to deliver the 5-year capital program for the New York region based on the competitive bid pricing as summarized in Attachment 1 (AAE-17_Attach 1_TSS Savings Summary).

- Actual costs for 8 completed projects were scaled, based on the proportion of the work they represent, to the anticipated 5-year NY capital plan investment. The projects were completed using internal and external resources, depending on project.
- To model costs to deliver this same project work volume under the new arrangement, the unit and project risk costs bid for the 8 projects were multiplied by the work volumes derived from the actual cost analysis. Additional elements included in the bid, such as core team and fee, were incrementally added to develop a total cost model comparison.
- Pain/gain share was not reflected in this analysis

The analysis derived an estimate of savings of 13% from use of the RDV selected bid. The Company determined it appropriate to reduce these estimated savings by 50% as part of its review of the RDV approach to account for the limited sample of projects reviewed, and potential risks not reflected in the project sample. The resulting estimate of 6.5% savings was applied to the contractor element of the five-year capital plan, and totals $45 million as described in response to IR NM 154 MI-62 MM-62. The Company has proposed a tracker of CAPEX costs. If savings from the RDV exceed the 6.5% level, such savings would be reflected in actual capital costs and the benefit will flow directly to customers through the annual reconciliation of the CAPEX tracker.

3. Due to the unique and complex nature of each transmission project, an integrated design-build approach was pursued. By incentivizing the designer and constructor to work more closely together through the gain share mechanism described in data request IR NM 156 MI-64 MM-64, improvements can be jointly pursued in design quality, project risk management, and delivery efficiencies to reduce overall project costs. Work best suited to this incentive mechanism, such as the Transmission workload, reflect such characteristics as sufficient and complex workload to support increased associated overhead and management tasks (e.g., determination and auditing of an accurate target cost), isolatable risk elements, financially and commercial mature supply partners, and visibility of workload.

In contrast to transmission projects, distribution projects have more standard designs, a high proportion of construction costs to total project costs, and repeatable work methods matched to consistent types of work. To optimize the biggest value driver – construction costs -the arrangement is structured on a more predictable fixed-price unit rate agreement under which the contractor absorbs risks associated with delivery to scope, schedule, budget, and standards. As the distribution construction work has a different value driver and does not sufficiently possess the typical transmission project characteristics described above, no gain share mechanism has been provided for Distribution. Another consideration is that any potential benefit from gain share for distribution projects may be outweighed by the incremental overhead costs for administration.

Both contracts allow for pricing review in subsequent years.

4. IR NM 156 MI-64 MM-64 and NM 328 DPS 200 JJA-18 describe how gain share payments are calculated. Any gain share realized will be charged to the same accounts (in the same percentages of total costs) that incurred charges during project construction. These accounts include capital, cost of removal and capital related expense. The accounting rationale behind this approach is to ensure that any gain share is charged to the specific assets that were constructed at a reduced cost compared to the negotiated target cost.

5. The Work Proposals are developed and agreed jointly by NEPA and Company project team. Each Work Proposal includes the project target cost, which is built in part from the competitively bid unit rates. In addition, as described in data IR NM 328 DPS 200 JJA-8, the Work Proposal and associated project target cost are reviewed as part of the Work Proposal Submission Process, and a Commercial review is undertaken. Finally, the Company project manager and, subsequently, the RDV Governance Board are also required to agree to the entire Work Proposal.

Per the Management Audit action plan for Recommendation VIII-4, the Company will employ professional estimators to validate the RDVs' substation and transmission line project target costs as described in TGP 32 on Project Cost Estimating in Attachment 2 (AAE-17_Attach 2_TGP 32). In summary, the procedure calls for the RDVs' target prices to be compared to estimates independently prepared by the Company's professional estimators. Differences between the project estimates and target costs that exceed allowable tolerances must be reconciled between the RDV and the Company's estimators. If the differences cannot be reconciled, Niagara Mohawk may reject the difference. The process will be fully implemented, including completion of the US Cost estimating application, in FY2011.

6. No gain share has been awarded to date. The Total Core Team work authorization will reach final completion on March 31, 2010. However, contractual terms allow for final reconciliation to be completed within four months after the end of each fiscal year.

7. In accordance with Section 216.1 (a) of the Public Service Commission's ("Commission") regulations (16 NYCRR §216.l(a)), the Company filed with the Commission a copy of the Regional Delivery Venture Agreement between National Grid and Northeast Power Alliance LLC ("NEPA") on April 28, 2009. A redacted version is provided in Attachment 3 (AAE-17_Attach 3_RDVA) and a complete version will be filed separately.

Name of Respondent: Annemarie Loftus

Date of Reply: April 7, 2010

Date of Request: March 18, 2010
Due Date: March 29, 2010

Request No. CVB-9
NMPC Req. No. NM 290 DPS 162

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Christian Bonvin

TO: Infrastructure and Operations Panel

Request

1. Please provide the number of meters purchased under the Meter Blanket (installs & purchases) for each of the past five years and the projected number of meters to be purchased per year for FY11 through FY15.

2. Please explain why the Company is forecasting an increase in its Meter Blanket (installs & purchases) compared to actual historic spending.

3. Does the Company's forecast include the purchasing of any smart meters?

4. Please explain the increase in the outdoor lighting blanket budget compared to actual historic spending.

5. Are repairs to deficiencies found on outdoor lighting during the inspection process included under the outdoor lighting blanket? If not, where are those forecasted cost captured?

6. Please provide the number of meters purchased under the Distribution Transformer blanket for each of the past five years and the projected number of units to be purchased for FY11 through FY15.

7. Please explain why the Company is forecasting an increase in its transformer blanket, including any efforts to reduce system losses. Additionally, please provide cost comparisons between higher efficiency transformers and models purchased in recent years.

Form 103

Response:

1. Meters purchased under blanket projects:
    - FY2006 – 9,485
    - FY2007 – 12,482
    - FY2008 – 12,148
    - FY2009 – 14,223
    - FY2010 – 8,447 (invoiced through 3/26/2010)

    The Company does not currently project the number of meter units for the 5-year plan. Budgeting of the meter purchase blanket is done on a trended basis including a factor for both volume and commodity/inflationary changes over the prior fiscal year's forecast at the time the budget is being built. Factors applied to the FY2010 meter purchase blanket during the FY11-FY15 build were as follows:
    - FY2011 – Volume Increase 0% / Commodity/Inflationary Inc 6%
    - FY2012 -- Volume 1.0% / Commodity/Infl 9.8%
    - FY2013 -- Volume 2.0% / Commodity/Infl 6%
    - FY2014 -- Volume 1.5% / Commodity/Infl 5.3%
    - FY2015 -- Volume 1.5% / Commodity/Infl 6.8%

    See Attachment 1 (CVB-9_Attach 1_Meter and Transformer) for the calculations.

2. Please refer to Attachment 1 for the calculations that were used to develop the FY11 to FY15 meter and transformer blankets for installation and purchases. The increase budgeted for FY2011 was based on the FY2010 forecast at the time of the budget build process. The factors mentioned in the response to question 1 of this request were applied to the prior year forecasts. The volume factors were based on an overall expected trend of the short term economy being flat and longer term economic growth in the 1-2% range as historically experienced. Lastly, installation factors are based on expected wage increases of the work force.

    The forecasts for these blankets are reviewed at divisional work planning meetings and are adjusted depending on how actual and expected costs are experienced throughout the year. While trends in these blankets would more than likely follow economic conditions, they are not directly proportionate to sales/load figures. The mix of meters purchased, size of the customers serviced, replacement requirements and other factors all play a role in the actual spending within the meter blanket projects. Volume factors are reviewed annually during the spending plan development cycle.

3. The current capital plan does not include any forecast for the purchase of smart meters. The Company filed a separate, comprehensive Smart Grid filing in January 2010.

4. Similar to the meter blankets mentioned in our response to question 1, budgeting of the outdoor lighting blanket is done on a trended basis including a factor for both volume and commodity/inflationary changes over the prior fiscal year's forecast at the time the budget is being built. Factors applied to the FY2010 outdoor lighting blanket during the FY11-FY15 build were as follows:
    - FY2011 – Volume Increase 0% / Commodity/Inflationary Inc 4.1%
    - FY2012 – Volume 0% / Commodity/Infl 5.6%
    - FY2013 – Volume 0% / Commodity/Infl 4.1%
    - FY2014 – Volume 0% / Commodity/Infl 3.8%
    - FY2015 – Volume 0% / Commodity/Infl 4.4%

    See Attachment 1 (CVB-9_Attach 1_Meter and Transformer) for the calculation. This does not include the Mercury Vapor Conversion project work which is being performed under project C26839.

5. Capital repairs to street lights which result from an inspection either under the Elevated Voltage (annual) or I&M program (5-year cycle) would be captured under the divisional outdoor lighting blanket project which also include other types of work such as luminaire replacement.

6. (Note: Christian Bonvin confirmed via e-mail on March 19, 2010 that the word 'meters' was a typographical error and the question actually refers to transformers)

Transformers purchased under blanket projects:

- FY2006 – 14,156
- FY2007 – 13,314
- FY2008 – 12,006
- FY2009 – 10,303
- FY2010 – 11,622 (invoiced through 3/26/2010)

We do not currently project the number of transformer units for the 5-year plan. Budgeting of the transformer purchase blanket is done on a trended basis including a factor for both volume and commodity/inflationary changes over the prior fiscal year's forecast at the time the budget is being built. Factors applied to the FY2010 transformer purchase blanket during the FY11-FY15 build were as follows:

- FY2011 – Volume Increase 0% / Commodity/Inflationary Inc 12%
- FY2012 -- Volume 1.5% / Commodity/Infl 9.8%
- FY2013 -- Volume 2.5% / Commodity/Infl 6.0%
- FY2014 – Volume 1.0% / Commodity/Infl 5.3%
- FY2015 -- Volume 1.0% / Commodity/Infl 6.8%

See Attachment 1 (CVB-9_Attach 1_Meter and Transformer) for the calculations.

7. The increase budgeted for FY2011 was based on the FY2010 forecast at the time of the budget build process. The factors mentioned in the response to question 6

of this data request were applied to the prior year forecasts. The volume factors were based on an expectation of the short term economy/load being flat and longer term economic growth in the 1-2% range as historically experienced.

The estimated cost increase for higher efficiency transformers versus those recently purchased is approximately 13%.

Name of Respondent:	Date of Reply:
Glen DiConza	03/30/2010

Form 103

Niagara Mohawk Meter and Transformer Blanket Budget Calculation

Meters	[redacted]	FY11 CAPITAL BUDGET		FY12 CAPITAL BUDGET		FY13 CAPITAL BUDGET		FY14 CAPITAL BUDGET		FY15 CAPITAL BUDGET	
		Vol	Infl	Vol	Infl	Vol	Infl	Vol	Infl	Vol	Infl
Meters - Dist	740,000	[redacted]									
INSTALL NE (Eastern Division)		0.0%	3.1%	1.0%	3.3%	2.0%	3.1%	1.5%	3.0%	1.5%	3.1%
Meters - Dist	650,000	[redacted]									
INSTALL NC (Central Division)		0.0%	3.1%	1.0%	3.3%	2.0%	3.1%	1.5%	3.0%	1.5%	3.1%
Meters - Dist	695,000	[redacted]									
INSTALL NW (Western Division)		0.0%	3.1%	1.0%	3.3%	2.0%	3.1%	1.5%	3.0%	1.5%	3.1%
Meters - Dist	4,700,000	[redacted]									
PURCH		0.0%	6.0%	1.0%	9.8%	2.0%	6.0%	1.5%	5.3%	1.5%	6.8%
Meters - Dist	6,785,000	[redacted]									
TOTAL		0.0%	5.1%	1.0%	7.9%	2.0%	5.2%	1.5%	4.6%	1.5%	5.8%

Transformers	[redacted]	FY11 CAPITAL BUDGET		FY12 CAPITAL BUDGET		FY13 CAPITAL BUDGET		FY14 CAPITAL BUDGET		FY15 CAPITAL BUDGET	
		Vol	Infl	Vol	Infl	Vol	Infl	Vol	Infl	Vol	Infl
Transformer - Dist	23,900,000	[redacted]									
PURCH		0.0%	12.0%	1.5%	9.8%	2.5%	6.0%	1.0%	5.3%	1.0%	6.8%

Purchase blanket estimated 75% materials 25% labor (Cap OH, Stores Handling, etc)

Street Lighting	[redacted]	FY11 CAPITAL BUDGET		FY12 CAPITAL BUDGET		FY13 CAPITAL BUDGET		FY14 CAPITAL BUDGET		FY15 CAPITAL BUDGET	
		Vol	Infl	Vol	Infl	Vol	Infl	Vol	Infl	Vol	Infl
Outdoor Lighting	1,800,000	[redacted]									
NE (Eastern Division)		0.0%	4.1%	0.0%	5.6%	0.0%	4.1%	0.0%	3.8%	0.0%	4.4%
Outdoor Lighting	2,800,000	[redacted]									
NC (Central Division)		0.0%	4.1%	0.0%	5.6%	0.0%	4.1%	0.0%	3.8%	0.0%	4.4%
Outdoor Lighting	3,250,000	[redacted]									
NW (Western Division)		0.0%	4.1%	0.0%	5.6%	0.0%	4.1%	0.0%	3.8%	0.0%	4.4%
	7,850,000	[redacted]									

Date of Request: March 18, 2010
Due Date: March 29, 2010

Request No. DAG-12
NMPC Req. No. NM 292 DPS 164

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Exhibit_(RRP-2), Schedules 12-17 Other Costs and Credits

The RRP testimony at page 23 references Exhibit __ RRP-2, Schedules 11-17 as "Other Costs and Credits" and includes the following:

Schedule 12 – Exp Type #A40 – Construction Reimbursement
Schedule 13 – Exp Type #A41 – Company Contributions / Credits to Jobs
Schedule 14 – Exp Type #A42 – Bill Interface Expense Type
Schedule 15 – Exp Type #A50 – Capital Overheads
Schedule 16 – Exp Type #A60 – Supervision and Administration
Schedule 17 – Exp Type #A65 – Service Company Operating Costs

1. For each of the above expense types, please provide a detailed explanation of what the expense cost is supposed to encompass and represent, how the cost is calculated, and on what basis does the charge come through to Niagara Mohawk (Co 36).

2. For the expense types where no normalizing adjustments were made to the historic test year, please explain and provide the analysis the Company undertook to determine that the actual historic test year amounts were reasonable and needed no adjustments, in forecasting the rate years.

3. For the expense types where normalizing adjustments were made to the historic test year, please explain and provide the analysis the Company undertook to determine the actual historic test year amounts with these adjustments, was a reasonable level, in forecasting the rate years.

Response:
Part 1 –
Schedule 12 – Exp Type #A40 – Construction Reimbursement

Expense Type A40 represents money received as an advance from customers, businesses, and others for construction activities on third party assets. These construction activities generally are for work performed on customer owned equipment or on company owned equipment that require a customer contribution.

The amounts billed to the respective parties are based on the cost of services and materials to be provided to each individual job.

When payment is received, the amount is credited back to the general ledger as Expense Type A40 to offset the anticipated costs of performing the work.

Schedule 13 – Exp Type #A41 – Company Contributions / Credits to Jobs

Expense Type A41 represents situations where Niagara Mohawk Power Corporation is responsible for a proportion of the costs of a job that is billed to a third party. For the same types of services described above under Expense Type A40, a complete job occasionally has shared financial responsibility for the cost between the customer and the Company.

The amount that is calculated is based on the services and materials provided to each individual job and a determination is made as to the percentage and share of financial responsibility attributable to the third party and to the Company respectively.

At the time of billing, a customer share percentage is entered based on the arrangement with the customer. An automated process within the billing application uses this percentage to appropriately credit the invoice for the Company's portion and will send a credit back to the general ledger as Expense Type A41, resulting in a partial offset to the costs of performing the work.

Schedule 14 – Exp Type #A42 – Bill Interface Expense Type

Expense Type A42 represents amounts billed to customers, businesses, and others for construction activities provided on third party assets, that are additional to advance payments (see A40 above). These construction activities generally are for work performed on customer owned equipment or on company owned equipment that requires a customer contribution.

The amounts that are billed to the respective parties are calculated based on the total amount incurred by the Company in providing the services and materials less any A40 payment received in advance from the customer.

When payment is billed, the amount is credited back to the general ledger as Expense Type A42 to offset the costs of performing the work.

Schedule 15 – Exp Type #A50 – Capital Overheads

Expense Type A50 represents the allocated cost of capital supervision and administrative expense associated with the construction of assets.

Capital supervision and administrative expense generally includes charges from field operation supervisors, district engineers, field operations management, and accounting services where they are working to support the capital construction program but cannot charge a specific project. The costs are collected in a pool to be distributed over the current period's capital spending (charges to 107 CWIP) using a standard percentage. The percentage rates used are calculated monthly by Plant Accounting based on the amount accumulated in the pools and the estimated monthly capital spends.

The charge is applied during month end accounting close processing and is charged directly to capital work orders.

Schedule 16 – Exp Type #A60 – Supervision and Administration

Expense Type A60 represents the allocated cost of Supervision and Administration which is to recover operating company only supervision and administrative charges supporting employees working in the field. This covers functions such as Accounting, Finance, Human Resources, Information Technology, Facilities, Legal, etc. for each Originating Business Unit that has employees.

The charge is applied to payroll (regular pay and overtime base pay for monthly and weekly employees) billed to associated companies or third parties during month end accounting close processing. Accounting Services reviews the rates monthly and adjusts them as needed. This is the method between all of the operating companies with only one exception. On Niagara Mohawk, third party work is charged at a PSC stated rate of 16.14% applied to all charges excluding payments received.

The charge is applied during month end accounting close process.

Schedule 17 – Exp Type #A65 – Service Company Operating Costs

Expense Type A65 represents the allocated cost of Supervision and Administration which is to recover Service Company only supervision and administrative charges supporting Service Company employees. This covers functions such as Accounting, Finance, Human Resources, Information Technology, Facilities, Legal, etc. for Service Company only.

The cost is collected in a clearing account on Service Company. The account is cleared using a percentage rate applied to payroll of the Service Company (regular pay and overtime base pay for monthly and weekly employees) billed to associated companies or third parties. The rate is developed monthly by reviewing the total current month charges, plus any unallocated charges from the prior month are divided by the current month's productive payroll to calculate an estimated rate.

The charge is applied during month end accounting close process.

Parts 2 & 3-

As described in the Company's response to Part 1.a and .b of IR DPS 138 DAG-4 on March 23, 2009, an analysis was performed on all expense types by project to analyze year over year variance and scrutinize projects for purposes of normalizing the historic test year. In addition, finance representatives from lines of business and shared service groups met regularly with regulatory personnel as part of the RCS process, described in the response to IR DAG-4, Part 9, to review year on year variance analysis between historic test year and forecast rate year. These individuals were provided a profile of the HY costs and asked to review this data and to address the following:

- Identify one time costs in the HY that may not be recurring in future years
- Review prior period costs booked in the HY
- Identify any corrections, transfers, adjustments etc.
- Identify any new major initiatives (not in HY) excluding NE Gas and KeySpan Costs to Achieve and Synergy Savings that would be incurred in Calendar Years 2011 through 2013
- Provide detailed descriptions of historic year costs and impact on rate year.

Name of Respondent:	Date of Reply:
Brian Langh	March 30, 2010

Date of Request: March 18, 2010
Due Date: March 29, 2010

Request No. DAG-13 SUPP
NMPC Req. No. NM 293 DPS 165

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Consultants Expense

1. For each of the following, provide a copy of all historic test year invoices with supporting documentation for the total historic test year costs incurred and charged to Niagara Mohawk (Company #36) either directly or indirectly. The supporting documentation should include the actual accounting applied so that verification of costs incurred can be reconciled with the historic test year workpapers provided in Exhibit __ (RRP-10).
(a) Harris Beach
(b) Morgan Lewis & Bockius
(c) The Energy Association of NY State
(d) Huron Consulting Services
(e) Equaterra Inc
(f) Accenture
(g) Icon Nicholson LLC
(h) Tata America International Corporation
(i) Davidson & O'Mara PC

2. For (a) – (i) listed in question #1 above, please provide a copy of the contract and purchase order the Company has with the vendor that supports and identifies the work being performed.

3. There is a listing on workpaper pages #35-36 for consultants expense in Exhibit __ (RRP-10) of journal id charges from business unit 00431 to Niagara Mohawk (Co. 36) that total $5,067,472. Based on workpapers provided by the Company, for the previous historic year ending 9/30/08, comparable journal id charges from business unit 431 to Niagara Mohawk was $2,349,006.
(a) Please reconcile and provide a detailed explanation of the significant increase of $2,718,466 between the historic year periods for business unit 431 charges coming to Niagara Mohawk.
(b) Based on workpapers #35-36, for each charge listed of $100,000 or more, please provide (i) a copy of the invoice(s) related to the charge and, if not provided on the invoice, a description and explanation of the work that was done and represented by the charge; (ii) the associated accounting that shows the allocation of the total invoice cost among the various

business units; (iii) the bill pool and explanation that supports the allocation used; (iv) and a copy of the purchase order supporting the vendor(s) invoice.
(c) Based on workpapers #35-36, for each charge listed of $100,000 or more, please provide a copy of the analysis that was done by the Company to conclude that the historic year charges incurred would be recurring in the rate years, and that the charges are not non-recurring in nature.

4. Workpaper page #7 for consultants expense in Exhibit __ (RRP-10) shows a listing of charges by originating company, by project, and by regulatory account that have been normalized in the historic test year to "remove one time costs related to the KeySpan Integration, WU 10310." The total of the electric expense normalizing adjustments for expense type #100 are $368,144. Please explicitly identify in the supporting workpapers on pages 12-48, the charges that make up the historic test year normalizing adjustments.

5. (a) For overall consultants expense, please explain and provide a copy of the analysis the Company undertook to determine that no additional normalizing adjustments to the historic test year were required, beyond the amounts provided on workpaper #7 and supported by the charges identified in question #4 above.

(b) Show how the analysis determines the remaining historic test year costs are reasonable and includes no non-recurring items, in that the normalized historic test year as presented by the Company is the basis in forecasting the rate years.

Response:

1. Please refer to attachments DAG-13 Attachment 1 and DAG-13 Attachment 1A.

2. Please refer to attachment DAG-13 Attachment 2.

3.
(a) As indicated in the workpapers, these charges originated from KeySpan Service Co. (Co. 431). Full service charging from KeySpan Service Co. to Niagara Mohawk did not begin until April 1, 2008. Prior to that date KeySpan Service Co. charges to Niagara Mohawk were de minimis. Therefore, the year ending September 30, 2008 includes only six months of these charges from KeySpan Service Co. while the historic test year ending September 30, 2009 contains twelve months of charges. This accounts for the approximate 115% from $2,349,006 in 2008 to $5,067,472 in 2009.

(b) Please refer to attachments DAG-13 Attachment 4 and DAG-13 Attachment 5.

(c) To comply with regulatory policy, the Company's approach to the review of Historic Year data was organized principally by expense type. For each expense type, the Company queried Historic Year (HY) data generally including information deemed relevant to the specific expense type (i.e. Company, Department, Activity, Segment, Bill Pool, Project, etc). Exhibit RRP-10, Workpaper to RRP-2, Schedule 4, Workpaper 2 – 5 is the result of this work. As described in the Company's response to Part 1.a and .b of IR DPS 138 DAG-4 on March 23, 2009, an analysis was done on all expense types by project to analyze year over year variance and to scrutinize projects for purposes of normalizing the historic test year. In addition, finance representatives from lines of business and shared service groups met regularly with regulatory personnel as part of the RCS process, described in the previous sited IR DAG-4, Part 9, to review year on year variance analysis between historic test year and forecasted rate year. These individuals were provided a high-level functional profile of the HY costs and asked to review this data and to address the following:

- Identify one time costs in the HY that may not be recurring in future years
- Review prior period costs booked in the HY
- Identify any corrections, transfers, adjustments etc.
- Identify any new major initiatives (not in HY) excluding NE Gas and KeySpan Costs to Achieve and Synergy Savings that would be incurred in Calendar Years 2011 through 2013
- Provide detailed descriptions of historic year costs and the impact on rate year.

As a result of these processes, there were no normalization adjustments to these KeySpan Service Co. charges identified, nor is there a specific document showing that a normalization adjustment was not warranted.

4. Please refer to attachment DAG-13 Attachment 3.

5. (a) and (b) The Company's approach to the review of Historical Year data was to organize it principally by expense type. For each expense type, the Company queried Historical Year (HY) data generally including information deemed relevant to the specific expense type (i.e. Company, Department, Activity, Segment, Bill Pool, Project, etc). Exhibit RRP- 10, Workpaper to RRP-2, Schedule 1, Workpapers 1 – 7 and Exhibit RRP-10, Workpaper to RRP-2, Schedule 2, Workpapers 1 – 8 are the result of this work. As described in the Company's response to Part 1.a and .b of IR DPS 138 DAG-4 on March 23, 2009, an analysis was done on all expense types by project to analyze year over year variance and scrutinize projects for purposes of normalizing the historical test year. In addition, finance representatives from lines of business and shared service groups met regularly with regulatory personnel as part of the RCS process, described in IR DAG-4, Part 9, to review year on year variance analysis between historical test year and forecasted rate year. These individuals were provided a high-level functional profile of the HY costs and asked to review this data and to address the following:

- Identify one time costs in the HY that may not be recurring in future years
- Review prior period costs booked in the HY
- Identify any corrections, transfers, adjustments etc.
- Identify any new major initiatives (not in HY) excluding NE Gas and KeySpan Costs to Achieve and Synergy Savings that would be incurred in Calendar Years 2011 through 2013
- Provide detailed descriptions of historic year costs and the impact on rate year.

Name of Respondent:	Date of Reply:
Donald Albers, James Molloy & John O Shaughnessy	April 30, 2010

Form 103

Date of Request: March 18, 2010
Due Date: March 29, 2010

Request No. DAG-13
NMPC Req. No. NM 293 DPS 165

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 10-E-0050 - Niagara Mohawk Power Corporation d/b/a National Grid
Electric Rates

Request for Information

FROM: Denise Gerbsch

TO: Revenue Requirement Panel

Request Consultants Expense

1. For each of the following, provide a copy of all historic test year invoices with supporting documentation for the total historic test year costs incurred and charged to Niagara Mohawk (Company #36) either directly or indirectly. The supporting documentation should include the actual accounting applied so that verification of costs incurred can be reconciled with the historic test year workpapers provided in Exhibit __ (RRP-10).
(a) Harris Beach
(b) Morgan Lewis & Bockius
(c) The Energy Association of NY State
(d) Huron Consulting Services
(e) Equaterra Inc
(f) Accenture
(g) Icon Nicholson LLC
(h) Tata America International Corporation
(i) Davidson & O'Mara PC

2. For (a) – (i) listed in question #1 above, please provide a copy of the contract and purchase order the Company has with the vendor that supports and identifies the work being performed.

3. There is a listing on workpaper pages #35-36 for consultants expense in Exhibit __ (RRP-10) of journal id charges from business unit 00431 to Niagara Mohawk (Co. 36) that total $5,067,472. Based on workpapers provided by the Company, for the previous historic year ending 9/30/08, comparable journal id charges from business unit 431 to Niagara Mohawk was $2,349,006.
(a) Please reconcile and provide a detailed explanation of the significant increase of $2,718,466 between the historic year periods for business unit 431 charges coming to Niagara Mohawk.

Form 103

(b) Based on workpapers #35-36, for each charge listed of $100,000 or more, please provide (i) a copy of the invoice(s) related to the charge and, if not provided on the invoice, a description and explanation of the work that was done and represented by the charge; (ii) the associated accounting that shows the allocation of the total invoice cost among the various business units; (iii) the bill pool and explanation that supports the allocation used; (iv) and a copy of the purchase order supporting the vendor(s) invoice.
(c) Based on workpapers #35-36, for each charge listed of $100,000 or more, please provide a copy of the analysis that was done by the Company to conclude that the historic year charges incurred would be recurring in the rate years, and that the charges are not non-recurring in nature.

4. Workpaper page #7 for consultants expense in Exhibit __ (RRP-10) shows a listing of charges by originating company, by project, and by regulatory account that have been normalized in the historic test year to "remove one time costs related to the KeySpan Integration, WU 10310." The total of the electric expense normalizing adjustments for expense type #100 are $368,144. Please explicitly identify in the supporting workpapers on pages 12-48, the charges that make up the historic test year normalizing adjustments.

5. (a) For overall consultants expense, please explain and provide a copy of the analysis the Company undertook to determine that no additional normalizing adjustments to the historic test year were required, beyond the amounts provided on workpaper #7 and supported by the charges identified in question #4 above.

(b) Show how the analysis determines the remaining historic test year costs are reasonable and includes no non-recurring items, in that the normalized historic test year as presented by the Company is the basis in forecasting the rate years.

Response:

1. Please refer to attachments DAG-13 Attachment 1 and DAG-13 Attachment 1A.

2. Please refer to attachment DAG-13 Attachment 2.

3.
(a) The Company is finalizing the response to this subpart and will submit under separate cover.

(b) Please refer to attachments DAG-13 Attachment 4 and DAG-13 Attachment 5.

(c) The Company is finalizing the response to this subpart and will submit under separate cover.

4. Please refer to attachment DAG-13 Attachment 3.

5. (a) and (b) The Company's approach to the review of Historical Year data was to organize it principally by expense type. For each expense type, then Company queried Historical Year (HY) data generally including information deemed relevant to the specific expense type (i.e. Company, Department, Activity, Segment, Bill Pool, Project,