

9/14/10
10-E-0050
248 (Vol 1)

Exhibit __ (SPP-1)

IR Responses

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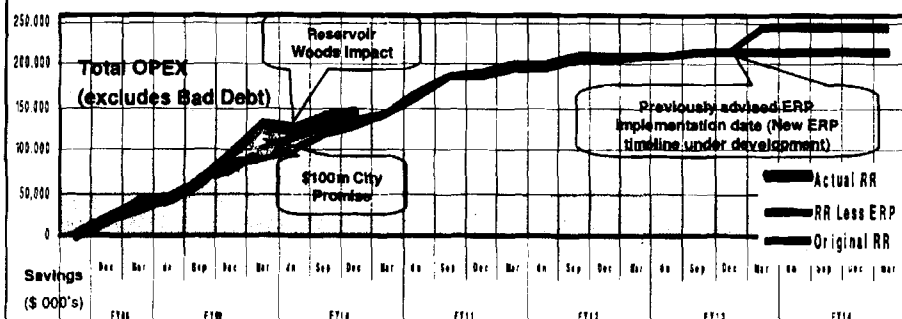
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DPS-109(DAG-2)(Redacted Version)

Synergy Savings Tracking to 31st December 2009:

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

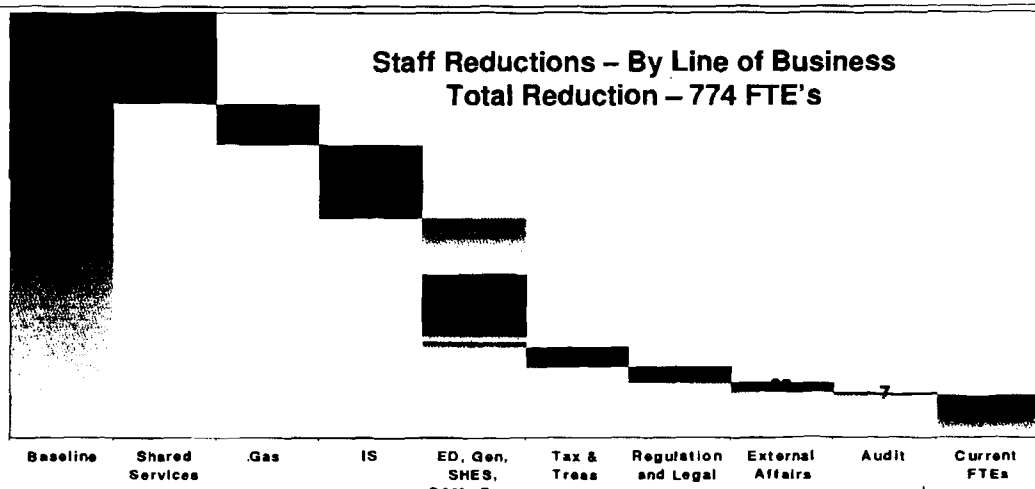
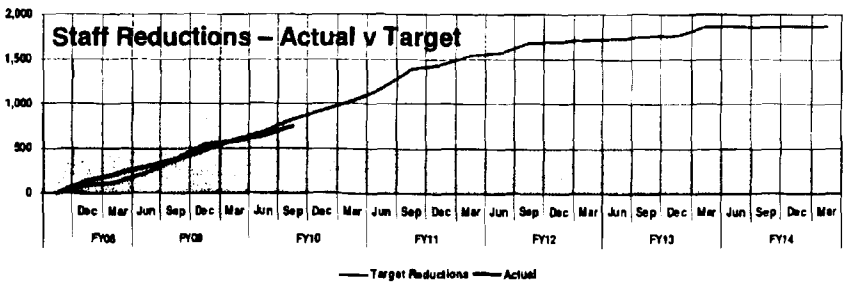
OPEX Reductions \$ in Millions	Q3 FY10			RR Dec 09			F'Cast RR Mar 10			Day N
	Act	Target	Var	Act	Target	Var	F'cast	Target	Var	Target
OPEX	106.0	93.5	12.4	190.3	133.4	16.9	156.7	144.1	12.6	226.6
Total Property	(2.6)	2.3	(5.3)	(4.6)	4.0	(8.6)	(4.6)	4.1	(8.7)	17.3
Total OPEX	103.3	96.2	7.2	145.7	137.4	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.



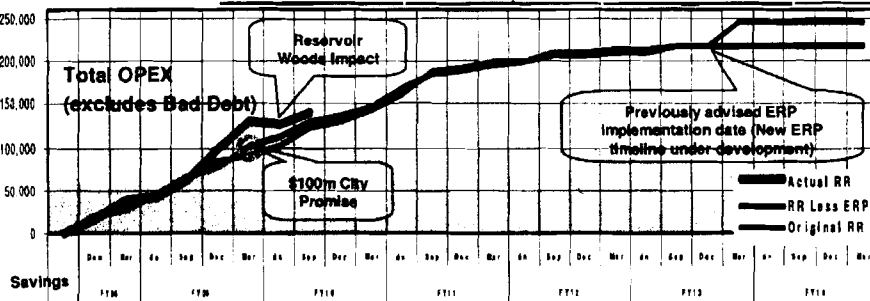
Electric Distribution 81.7, Generation 11, SHE's 32.5, C&M 125, Exec 15

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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.

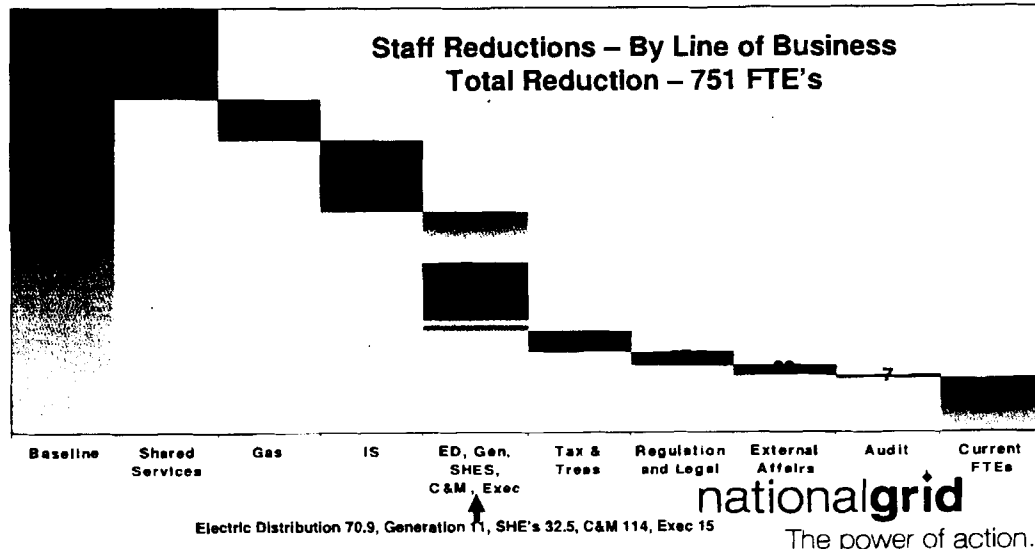
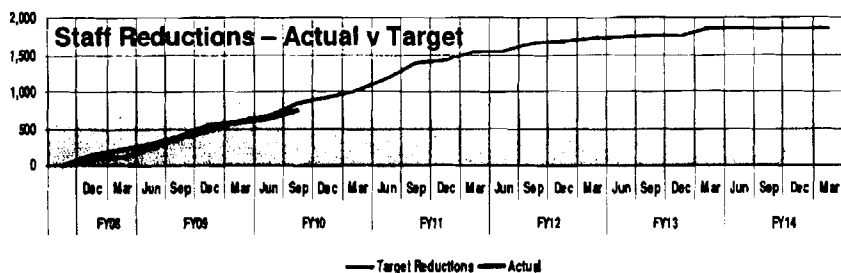
OPEX Reductions \$ in Millions	Q2 FY10			RR Sep 09			F'Cast RR Mar 10			Day N
	Act	Target	Var	Act	Target	Var	F'cast	Target	Var	Target
OPEX	66.6	60.2	6.4	145.4	128.9	16.5	158.1	146.7	12.4	229.6
Total Property	(1.5)	1.6	(3.2)	(4.8)	3.4	(8.2)	(4.8)	4.1	(9.0)	17.3
Total OPEX	65.0	61.8	3.2	140.5	132.3	8.3	154.2	150.8	3.4	246.9
Bad Debt & Weather Hedge	20.3	9.7	10.7	29.2	21.5	6.7	38.6	25.8	12.8	40.7
Grand Total	85.4	71.4	13.9	169.7	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.

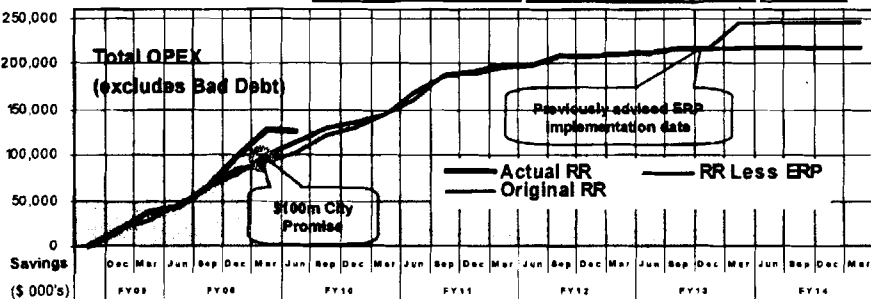
- 751 employee positions eliminated as of 30th September 2009; falling below target (FY10 Q2 target is 830). (Figures exclude contractors.)
- The cancelled Gas AMR and lack of a single customer system has caused the FTE savings gap to widen over the quarter and is projected to continue to do so by year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



Synergy Savings Tracking to 30th June 2009:

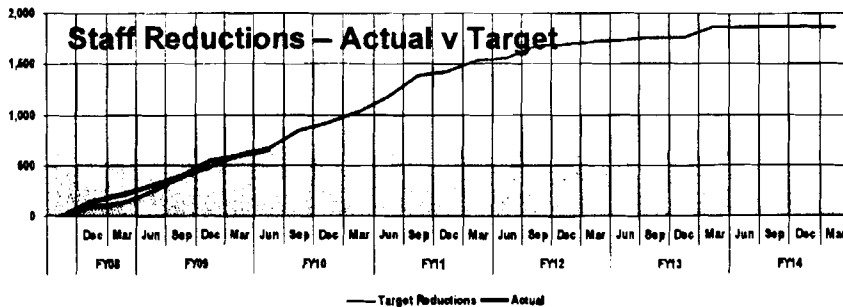
Run Rate target exceeded but down on prior quarter / FTE's slightly below target

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



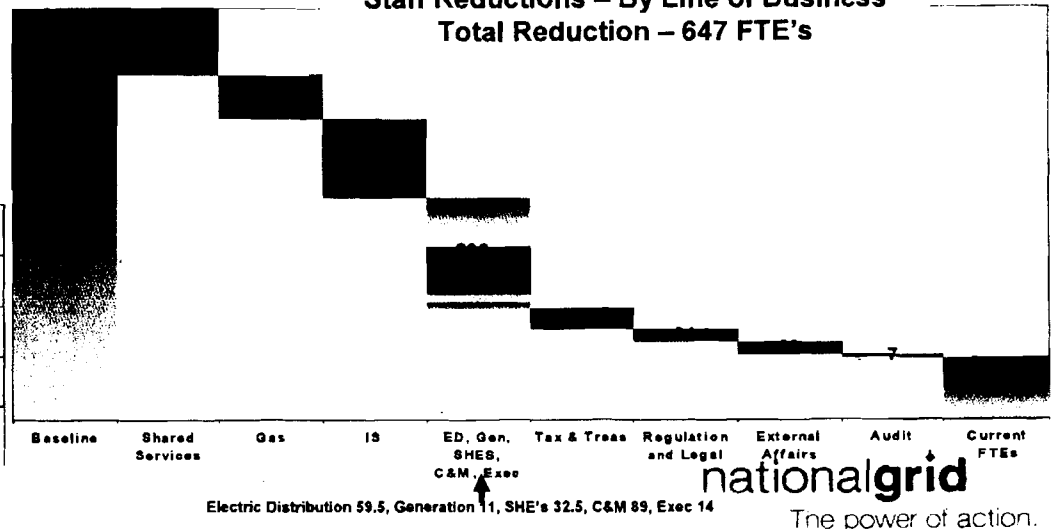
Original City Promise: \$100M / £67M run rate exceeded - \$200M final target to be achieved

- 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.



- 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.

Staff Reductions – By Line of Business Total Reduction – 647 FTE's



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

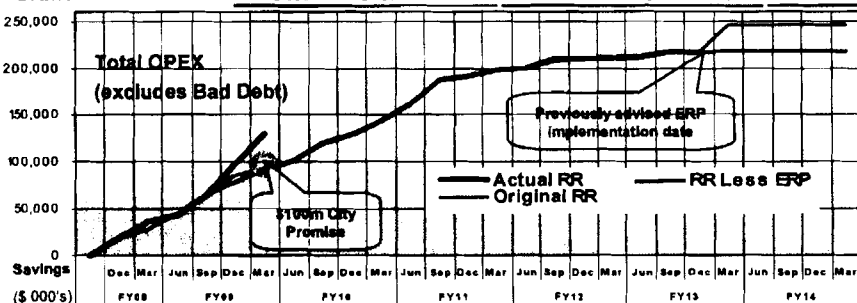
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Synergy Savings Tracking to 31st March 2009:

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

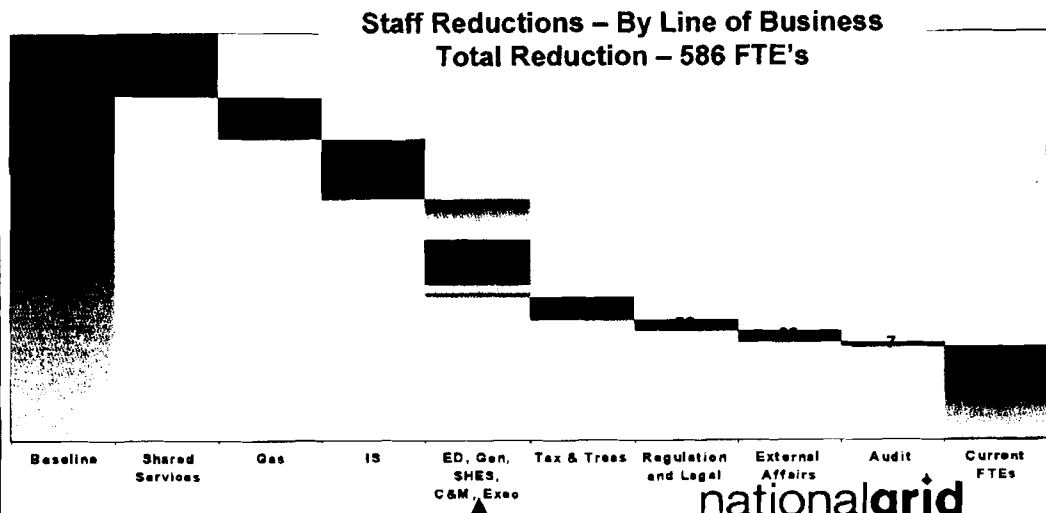
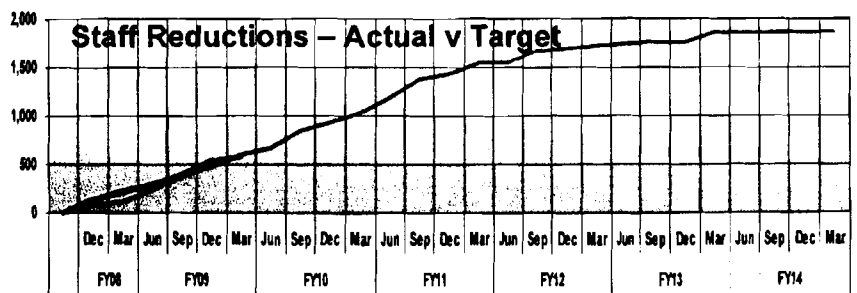
OPEX Reductions \$ in Millions	Actual Savings FY09			Run Rate March 09			Day N
	Act	Target	Var	Act	Target	Var	Target
OPEX	71.6	73.4	(1.8)	124.5	97.9	26.7	230.1
Total Property	4.7	2.6	2.1	6.1	3.0	3.1	16.8
Total OPEX	76.2	76.0	0.3	130.7	100.9	29.8	246.9
Bad Debts	15.4	8.0	7.4	26.2	12.3	13.9	40.7
Grand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

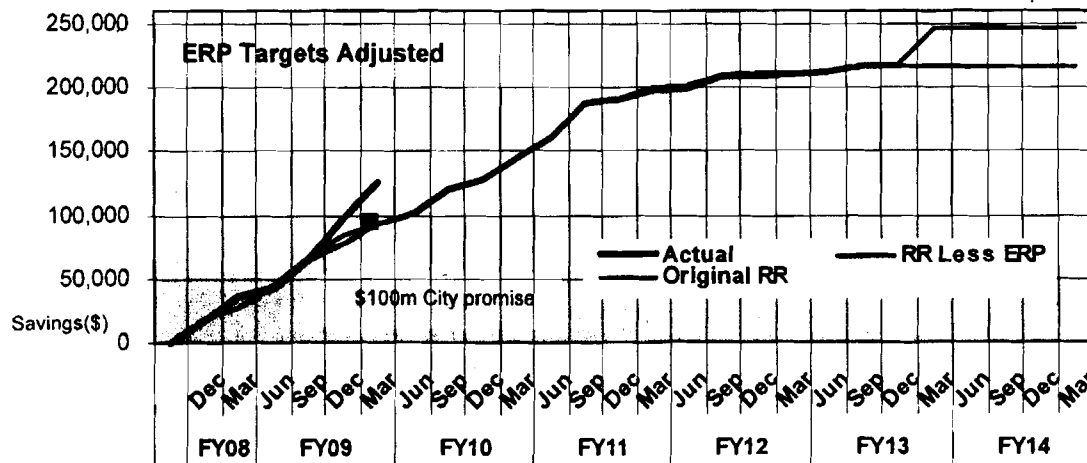


Electric Distribution 44, Generation 11, SHE's 32.5, C&M 84, Exec 14

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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			Run Rate Basis			Run Rate Basis			Day N
	08/09 Q1, Q2 & Q3			As at Dec 08			As at Mar 09			Target
	Act	Target	Var	Act	Target	Var	F'cast	Target	Var	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	1.8	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	60.3	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	63.3	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	66.3	54.4	1.9	105.0	93.9	11.1	136.6	105.2	31.4	287.6

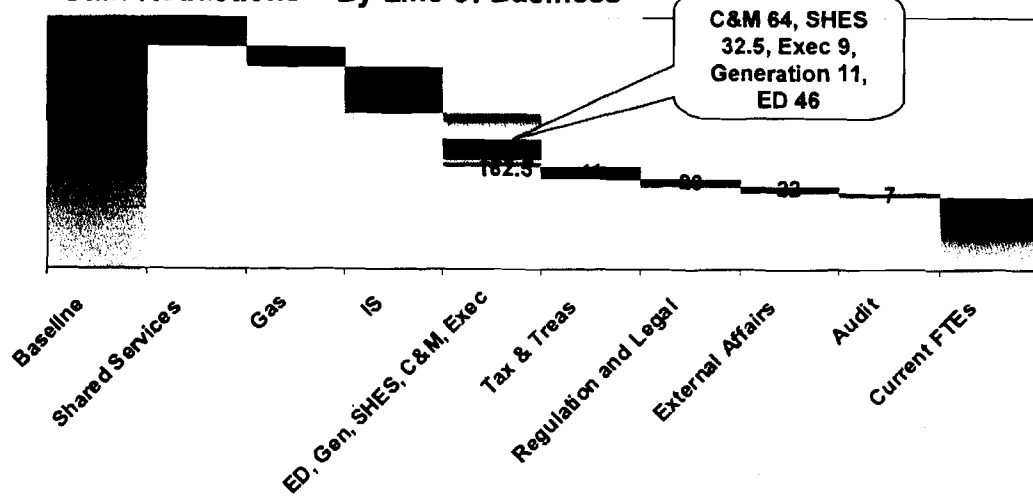


City Promise: \$100M / £67M run rate target at the end of the first full year

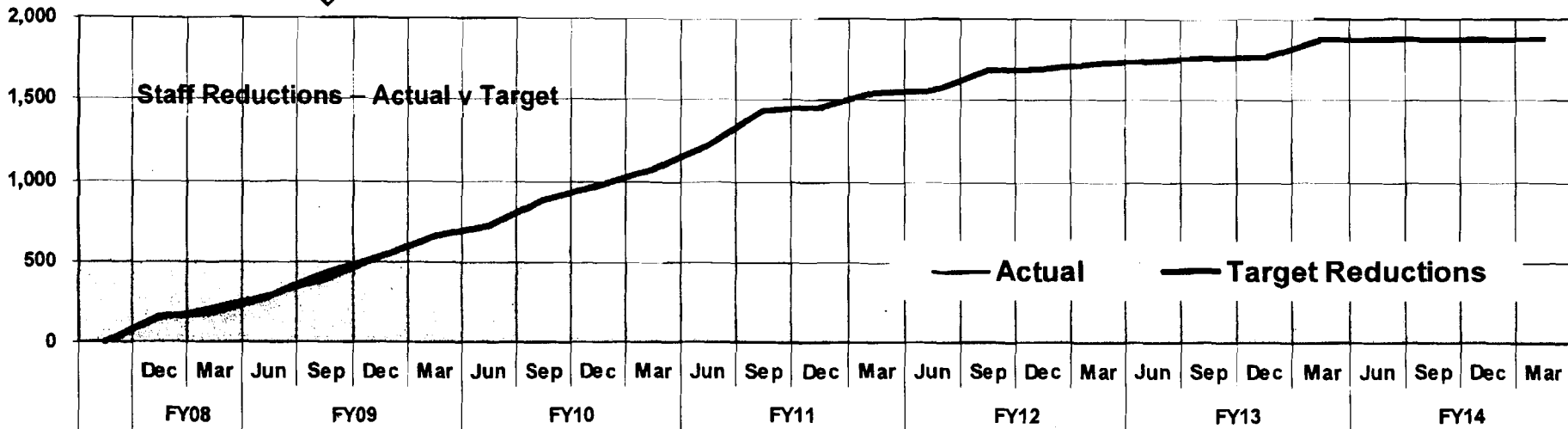
- December 08 run rate is closing in on the \$100m City promise.
- Run rate growth across the final quarter is forecast to drive the year end March 09 run rate to circa \$125m (excluding bad debt synergies).
- Recognition of Reservoir Woods costs (a negative synergy) will be delayed until the expected 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 2011 (but remain in the Day N target)

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

Staff Reductions – By Line of Business

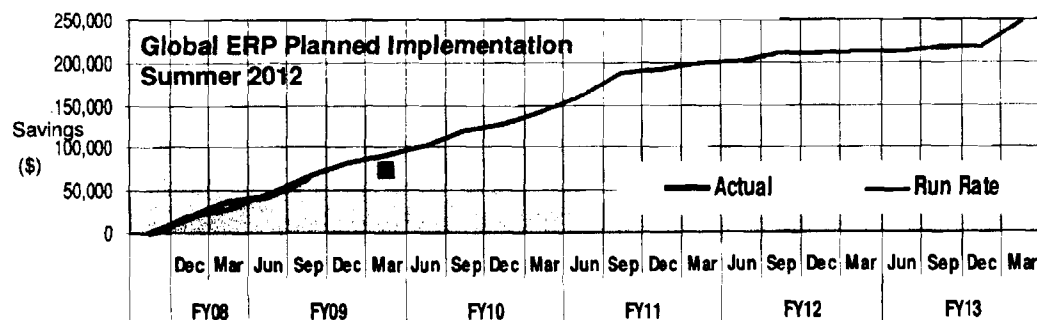


- 540 employee positions eliminated as of 31st December 2008; 66 ahead of schedule
- Electric Distribution and IS were key contributors although the AMR project and revision of initiatives in customer and markets have led to some re-phasing.
- Double manning is assumed to be charged as exceptional and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



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		Run Rate Basis		Run Rate Basis		Day N
	08/09 Q1 and Q2		As at Sept 08		As at Mar 09		Target
	Act	Var	Act	Var	F'cast	Var	
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

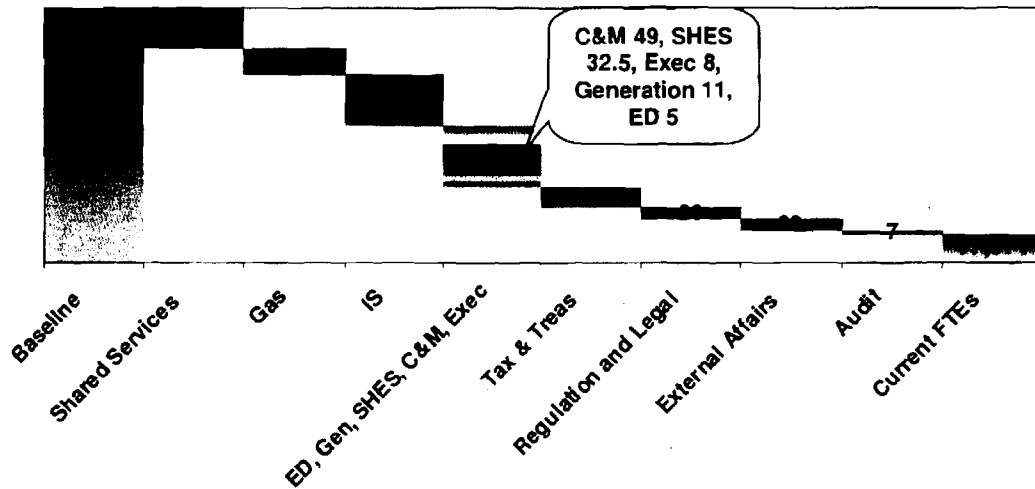
- Two key projects are driving total savings to fall behind target. The AMR (Gas) project has been significantly scaled back as it did not receive the required regulatory approvals and Contact Center initiatives (Customer & Markets) are behind schedule. Consolidation schedule has been impacted by labor 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.

nationalgrid

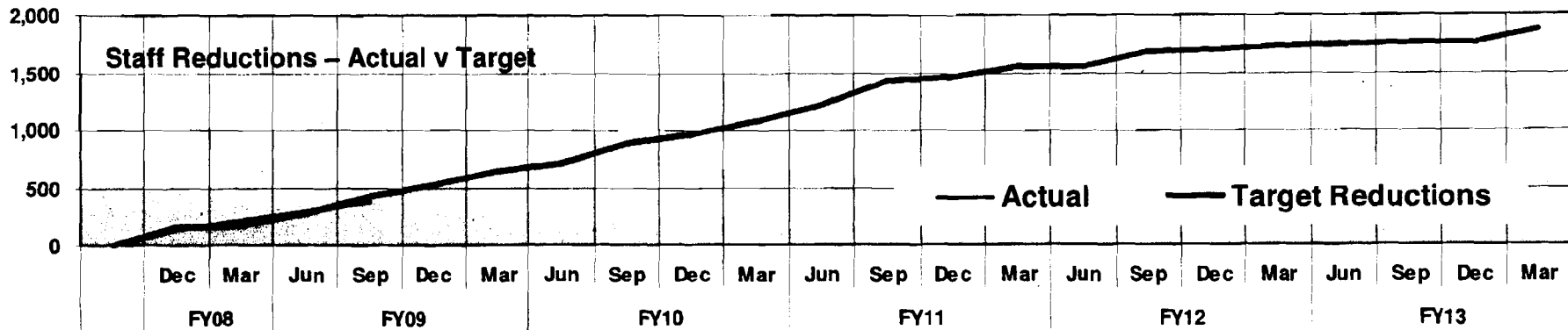
The power of action.

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

Staff Reductions – By Line of Business

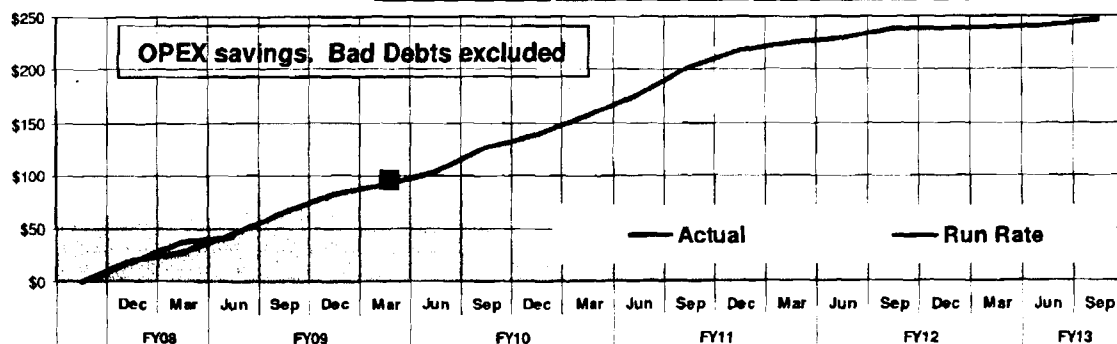


- 388 employee positions eliminated as of 30th September 2008; 37 behind schedule
- Principal issues are the AMR project, Outsourcing Contact Center and the increased volume and complexity of calls
- Double manning is assumed to be charged as exceptional and therefore not impacting synergies or the headcount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



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

OPEX Reductions \$ in Millions	Fiscal Year Basis		Run Rate Basis		Target	Day N
	FY 08/09 Q1		As at June 08		Run Rate	Target
	Act	Var	Act	Var	Mar 09	
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



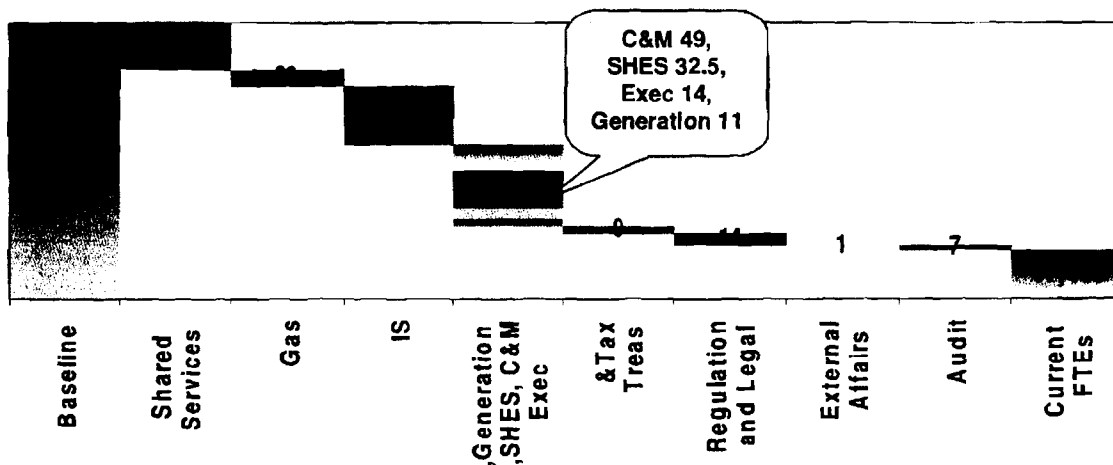
■ City Promise: \$100m run rate target at the end of the first full year

- 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.

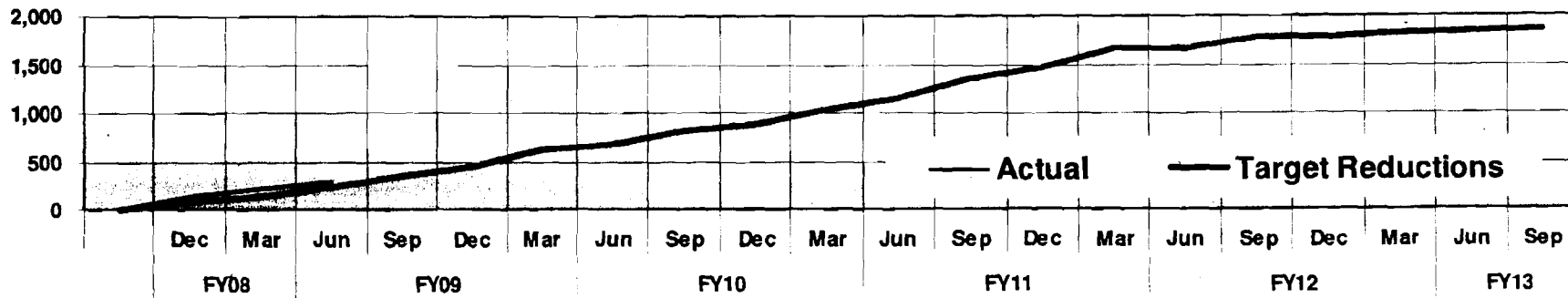
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FTE Bridge & Tracking to 30th June

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.



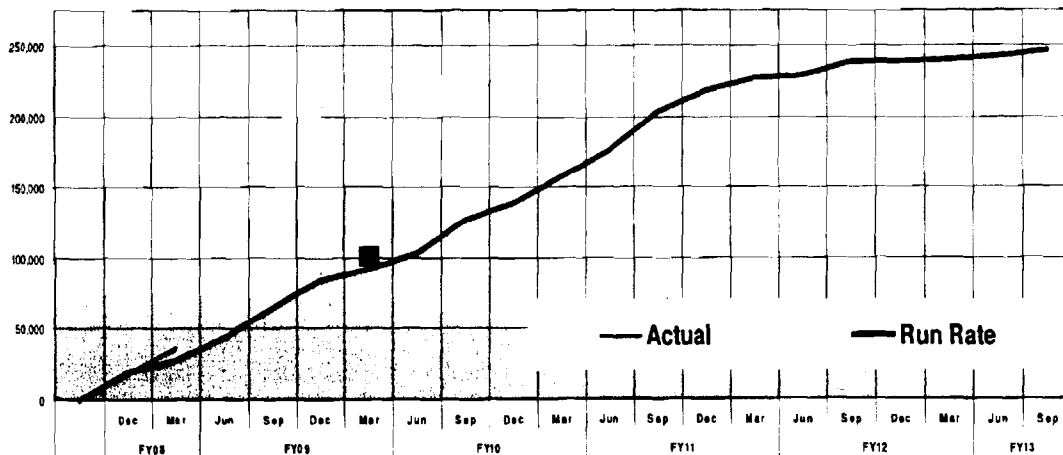
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Savings Tracking to 31st March: Initial View

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			Run Rate Basis			Day N Target
	FY08 Year End			Run Rate at Mar 08			
	Act	Target	Var	Act	Target	Var	
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 Support	\$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



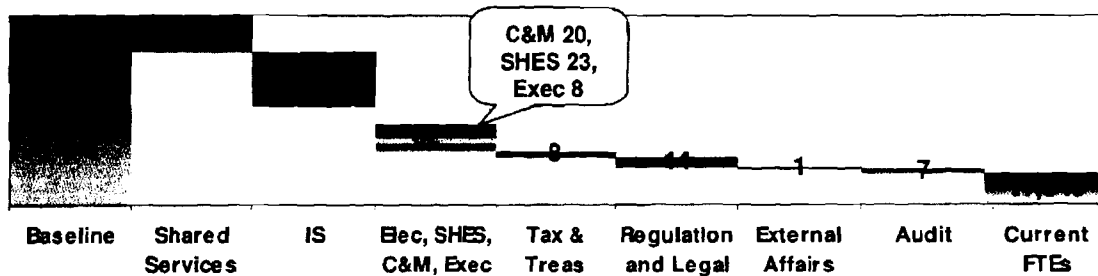
■ City Promise: \$100m run rate target at the end of the first full year

- 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

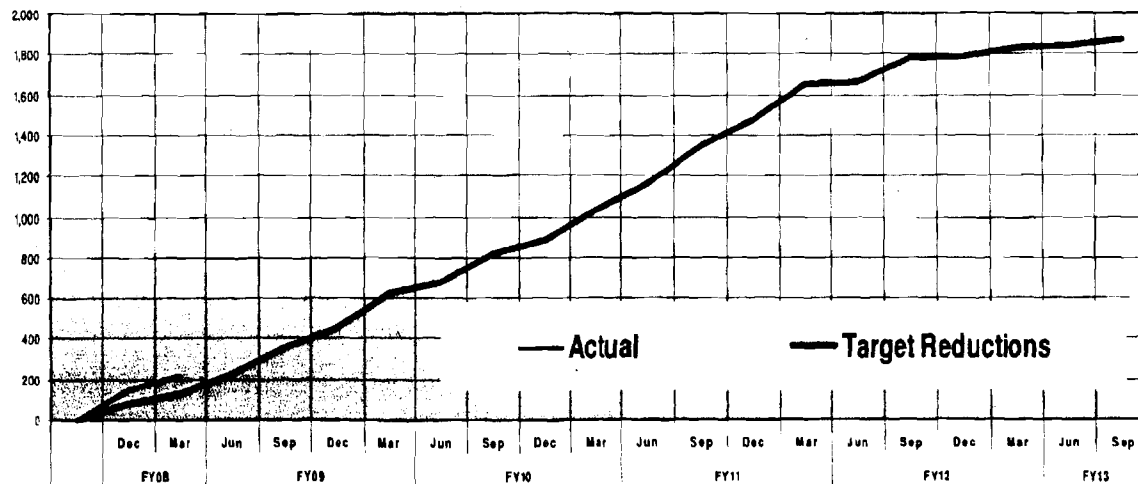
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FTE Bridge & Tracking to 31st March

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



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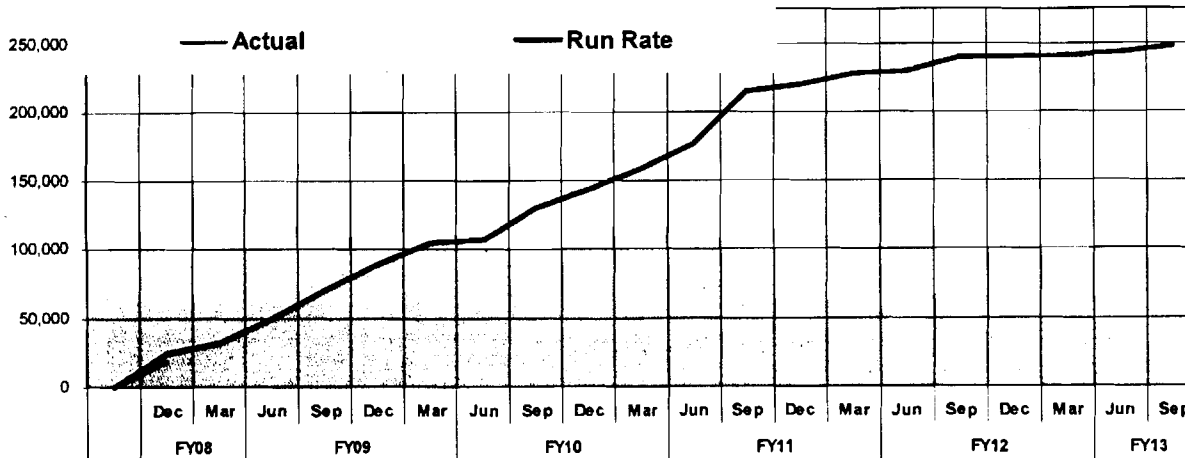
US Integration Synergies

Summary Savings - Preliminary Tracking to December 2007

OPEX Reductions \$ in Millions

	Qtr Dec 07			FY08 Year End			Run Rate			Day N	
	Act	Target	Var	Act	Target	Var	Act	Target	Var	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	1.8	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

nationalgrid

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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

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

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 Opinae 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 Billing BU	-	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 Srvc 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 Naamasket 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	56,981	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	14,906,347	16,066,770	20,103,242	20,293,489	18,328,468	192,708,260
00037 Opiacac 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	4,533,622
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	-	-	-	-	-	-	-	-	-	114,056
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
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 Opinec 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	127,181	2,940	68,021	(139)	-	1,692,712
00079 National Grid Wirelss 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 Brlklyn Union Gas KEDNY Bill BU	-	-	-	-	-	-	-	-	11,749,295	8,267,717	9,857,450	10,759,457	40,633,919
01442 KS Ravenswood Srvc 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 Fort 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 Upthur 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	100,649,872	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	112,292	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	19,322,755	14,813,575	16,620,255	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	5,318,971	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	35,697	28,056	28,198	51,313	33,310	421,005
00021 National Grid Trans Services	3,337	4,650	2,674	3,057	3,121	2,394	3,064	2,896	1,058	1,095	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	22,965,592	29,319,342	23,959,179	21,357,483	24,345,323	271,807,390
00037 OpInac North America, Inc	-	-	-	175	-	-	-	-	-	-	-	-	375
00041 Granite State Electric Company	738,280	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	(4,273)	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	(17,161)	6,216,691
00076 NGrid Communications Billing	-	(67,303)	-	-	-	-	-	-	-	-	-	-	(67,303)
00082 GridAmerica Holdings	-	(43)	450	-	1,637	92	-	-	-	-	-	-	1,137
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	7,755,664	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)	(2,156)	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	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 Serv Billing BU	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 KEDNY Bill BU	5,684,891	7,280,050	13,606,633	5,915,661	8,964,904	9,216,505	5,929,128	7,697,810	8,104,934	8,511,774	7,748,794	8,817,524	97,478,708
01438 Briksys 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 Svcs 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	3,210,041	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 Clewwood 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	2,548,695
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)	(1,828,392)	(1,827,667)	(1,788,485)	(1,738,306)	(1,876,333)	(1,310,045)	(1,542,933)	(1,812,375)	(1,828,767)	(1,664,483)	(20,658,581)
01471 Seneca Upakar 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
02 NG Ravenswood SERV (post Sale)	-	-	-	-	-	-	-	-	2,949,558	2,343,852	2,093,315	2,656,072	10,042,797
01563 KeySpan EAP 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	82,380,317	95,840,824	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
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	24,151	38,885	(51,134)	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	1,257	3,038	1,473	3,226	3,086	3,328	3,332	36,895
00035 Niagara Mohawk Holdings, Inc.	-	-	-	120	-	4	(14)	-	-	-	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 Opisar 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 Appliances & 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	2,114,338	137,672	507,810	582,625	131,878	154,131	4,991,884
00082 GridAmerica Holdings	597	100	61,844	893	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	457	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	15,339	274,164	222,334	415,951	850,180
01403 Colonial Lower 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	1,710,924	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	584,494
01406 EnergyNorth Nat Gas Billing BU	492,346	912,946	1,206,111	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	235,446	205,623	187,875	408,695	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 Serv Billing BU	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 BU 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 Bklyn Union Gas KEDNY BU 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 Ravenwood Servs 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 Gleewood 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)	(1,800,856)	(20,071,787)
01471 Seneca Upstar Billing BU	80,555	92,941	260,477	44,951	54,015	82,569	43,360	60,199	74,235	49,572	50,718	84,937	978,489
82 NG RAVENWOOD SERV (post Sale)	1,584,246	2,030,069	3,442,668	10,312	1,867	(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
D1 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 Oplnac 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 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	-	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 Billing BU	-	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 Srves 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
01463 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	\$788,092,965	\$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 & Merchandis	-	-	-	-	-	-	-	-	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 Nausset Electric Company	186,506	177,075	293,682	105,626	131,332	123,495	137,121	204,723	113,100	128,639	142,167	142,941	1,886,808
00005 Massachusetts Electric Company	12,234,659	12,734,934	19,600,885	10,796,235	13,211,714	13,912,576	13,219,891	14,404,977	12,925,708	14,248,587	13,964,108	13,726,360	165,026,634
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	149,233	90,947	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	316	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	16,479,192	19,806,665	21,422,162	19,370,108	21,130,748	19,002,112	20,255,124	229,480,143
00037 Optima 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	5,152,535	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	1,702	12,518
00071 Valley Appliances & Merchandise	50	504	304	380	380	1,101	369	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 NRES 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 Prudance 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	(300)	240	199	270	670	182	2,549
01401 Boston Gas Company Billing BU	-	-	-	-	-	-	-	-	-	-	-	296	13,968
01403 Colonial Lowell Dtv Billing BU	-	-	-	-	-	-	-	-	-	-	59	-	2,762
01404 Colonial Cape Cod Billing BU	-	-	-	-	-	-	-	-	-	-	-	-	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 Billing BU	-	-	-	-	-	-	-	-	-	-	-	346	13,860
01435 KeySpan Generation Billing BU	-	-	-	-	-	-	-	-	-	-	152	3,507	3,659
01436 KeySpan Energy Dev Billing BU	-	-	-	-	-	-	-	-	-	-	0	47	47
01437 KS Gas East Corp KREDL Bill BU	-	-	-	-	-	-	-	-	-	-	198	9,261	9,459
01438 Brklyn Union Gas KREDNY Bill BU	-	-	-	-	-	-	-	-	-	-	444	20,852	21,296
01442 KS Ravenswood Svcs 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
01450 KS Energy Supply Billing BU	-	-	-	-	-	-	-	-	-	-	0	11	11
01459 KS Services Billing BU	-	-	-	-	-	-	-	-	-	-	18	736	753
01471 Seneca Upsher 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	\$35,837,385	\$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	58,994,548
00004 Nantucket Electric Company	172,165	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	53,192	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	27,378,248	22,167,431	21,388,695	22,492,949	255,504,904
00037 Opnarc 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	671,283	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	1,536	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 Essect Gas Company	32	64	(22)	942	2,342	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	482,314	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 Billing BU	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 Bklyn 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	532,362	5,231,141
01442 KS Ravenwood Svcs Billing BU	36,295	197,191	458,679	(414,883)	212,387	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 Fort 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	\$67,275,382	\$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	191,676	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	7,786,710	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	-	22,338,406
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	-	-	-	-	-	-	-	-	-	-	-	-	-
FI 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
NP 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
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	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
00045 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	-	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 Lowel Div Billing BU	79,685	350,522	304,785	131,318	158,073	298,858	154,541	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 Billing BU	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 Srvs 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	233,701	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	13,263,210	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	61,955	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)	6,951	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	251,707	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	2,507,619	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	3,929,055.24
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

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 (\leq \$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.

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:

Glen DiConza

Date of Reply:

February 18, 2010

BLANKET CAPITAL PROJECT ANALYSIS
 NIAGARA MOHAWK (\$000)
 DISTRIBUTION

COLUMN											
A	B	C	D	E	F	G	H	I	J	K	L
	Blanket # / Blanket Description		FY05/06 Actual Spend		FY06/07 Actual Spend		FY07/08 Actual Spend		FY08/09 Actual Spend		
1	002 Substation Blanket	-	882	-	767	750	955	780	1,190	1,099	1,979
2	004 Meter Blanket (installs & purchases)	2,024	2,389	2,700	4,943	5,800	6,691	6,058	5,661	7,006	3,350
3	006/070 Genl Equip Blanket	1,475	2,155	1,300	810	1,000	1,460	614	8,275	847	3,177
4	009 Land/Rights Blanket	-	1,478	1,210	1,776	1,750	1,154	1,820	1,718	1,945	1,919
5	010 New Bus-Resid Blankt	31,202	41,227	34,200	41,439	46,600	35,055	36,756	29,649	25,492	27,724
6	011 New Bus-Comm Blanket	3,206	10,973	8,500	9,426	10,900	11,466	10,968	11,516	9,245	12,166
7	012 Outdoor Lighting	6,873	7,082	6,700	7,029	7,900	7,361	6,596	8,113	7,258	6,400
8	013 Public Requir Blankt	6,841	9,590	7,000	8,290	9,690	15,417	8,756	3,212	7,340	4,282
9	014 Damage&Failure Blnkt	5,091	8,161	6,300	11,232	10,700	13,044	13,098	14,175	18,241	15,213
10	015 Reliability Blanket	1,783	6,737	4,500	5,079	6,200	4,220	4,869	7,270	7,432	8,428
11	016 Load Relief Blanket	2,363	6,715	4,500	1,355	2,000	1,001	1,360	1,334	2,685	1,375
12	017 Asset Replace Blankt	6,237	6,915	5,700	7,555	8,000	4,885	3,838	6,642	6,961	9,370
13	020 Transf/Capac Blanket	21,942	25,182	20,000	24,488	23,400	25,428	22,738	23,174	23,920	24,276
14	021 Dist - Telecom	428	510	550	64	150	(151)	156	1	24	(4)
15	022 3rd Party Attch Blnkt	156	457	500	292	450	128	468	156	262	294
16	TOTAL		130,453		124,545		128,114		122,086		

BLANKET CAPITAL PROJECT ANALYSIS
 NIAGARA MOHAWK (\$000)
 SUB-TRANSMISSION

COLUMN											
A	B	C	D	E	F	G	H	I	J	K	L
	Blanket # / Blanket Description		FY06/06 Actual Spend		FY06/07 Actual Spend		FY07/08 Actual Spend		FY08/09 Actual Spend		
23	071 New Business (All)	-	502	-	88	100	458	750	20	241	430
24	072 Public Requirements	492	556	460	920	(230)	(592)	750	85	145	55
25	073 Damage/Failure	1,023	1,533	1,725	1,332	1,950	1,709	1,600	2,812	1,304	2,750
26	074 Substation Blanket	-	54	25	180	555	427	750	829	757	972
27	075 Asset Replacement	180	694	460	576	460	1,995	2,909	1,321	716	1,400
28	076 Reliability	-	-	-	-	-	72	750	439	615	575
29	077 Load Relief	-	35	-	127	-	298	750	272	99	50
30	TOTAL		3,374		3,223		4,367		5,778		

ROW #

ROW #

ROW #	M	N	O	P	Q
1					
2	1,382	1,440	1,483	1,546	1,605
3	7,132	7,785	8,329	8,844	9,482
4	1,987	4,070	4,211	4,389	4,611
5	1,920	2,078	2,246	2,428	2,626
6	27,773	29,882	31,428	32,917	34,642
7	12,820	13,190	13,820	14,418	15,064
8	8,172	8,429	8,882	9,323	9,733
9	4,348	4,819	4,881	5,082	5,333
10	14,483	16,284	16,880	16,406	17,046
11	8,031	7,181	7,784	8,284	8,800
12	1,104	1,144	1,183	1,233	1,288
13	8,786	8,760	8,180	4,600	4,000
14	28,820	28,823	32,826	34,829	37,242
15	30	30	30	30	30
16	288	280	290	300	310
17					
18					
19					
20					
21					
22					
23					
24	831	843	874	898	918
25	284	283	289	316	331
26	3,087	3,181	3,368	3,364	3,442
27	832	886	917	831	881
28	830	886	886	1,031	1,060
29	814	828	842	888	889
30	106	110	114	118	122
31					

M	N	O	P	Q
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Niagara Mohawk Power Corp.
TxD Blanket Map

CVB-1
Attachment 2

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 maintenance 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 Stz		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	Capitalizable B-Maintenance	Capitalizable 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
Due Date: February 22, 2010

Request No. DPS-22(DSM-1)

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:

Dawn Travalini

February 22, 2010

Transmission Veg Management Rate Year Estimates

Transmission Veg Management Rate Year Estimates							
Vegetation Management Activities TRIM-STC-MOW (trim, prune/cut, stump treat & chip/mechanical brush mowing)	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)
	23 - 46	333	\$477,611.00	333	\$491,939.00	333	\$506,697.00
	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
INTEGRATED VEGETATION MANAGEMENT	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)
	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
DANGER TREE	Voltage (kV)	CY2011 (estimated miles)	CY2011 (projected cost)	CY2012 (estimated miles)	CY2012 (projected cost)	CY2013 (estimated miles)	CY2013 (projected cost)
	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
OFF-CYCLE	Voltage (kV)	CY2011	CY2011 (projected cost)	CY2012	CY2012 (projected cost)	CY2013	CY2013 (projected cost)
	23 - 345	unplanned hazard tree removals	\$440,840.00	unplanned hazard tree removals	\$454,065.00	unplanned hazard tree removals	\$467,687.00
SUB-T WIDENING	Voltage (kV)	CY2011 (projected miles)	CY2011 (projected cost)	CY2012 (projected miles)	CY2012 (projected cost)	CY2013 (projected miles)	CY2013 (projected cost)
	23 - 69	140	\$3,488,239.00	140	\$3,592,886.00	140	\$3,700,673.00
SUBSTATIONS	Voltage (kV)	CY2011 (acres)	CY2011 (projected cost)	CY2012 (acres)	CY2012 (projected cost)	CY2013 (acres)	CY2013 (projected cost)
	12 - 345	877	\$342,400.00	877	\$352,672.00	877	\$363,252.00
GRASS MOWING	Voltage (kV)	CY2011 (acres)	CY2011 (projected cost)	CY2012 (acres)	CY2012 (projected cost)	CY2013 (acres)	CY2013 (projected cost)
	23 - 345	1302	\$130,000.00	1302	\$133,900.00	1302	\$137,917.00
115 KV WIDENING	Voltage (kV)	CY2011 (projected miles)	CY2011 (cost)	CY2012 (projected miles)	CY2012 (cost)	CY2013 (projected miles)	CY2013 (cost)
	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
Due Date: February 22, 2010

Request No. DPS-23(DSM-2)

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

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:

Dawn Travalini

Date of Reply:

February 22, 2010

Date of Request: February 11, 2010
Due Date: February 22, 2010

Request No. DPS-24(DSM-3)

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:
Dawn Travalini

Date of Reply:
February 22, 2010

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

DPS-24(DSM-3)

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	4,091,368		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 Mats - 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
Due Date: February 22, 2010

Request No. DPS-24(DSM-3) [SUPP]

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.

Name of Respondent:
Dawn Travalini

Date of Reply:
February 23, 2010

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

DPS-24(DSM-3)

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		T2580	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 Mats - 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	T2580	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	T1800	Mortimer - Pannell Road #25	12/9/09 8:11	12/9/09 14:12	Y			Dry Snow, Strong Wind	2009	WG	Western
304908	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
Due Date: February 22, 2010

Request No. DPS-25(RAV-14)

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.

Name of Respondent:

Pat Michels

Date of Reply:

2/22/2010

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:

Kenneth Maloney & Maureen Heaphy

Date of Reply:

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.

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:

Lori Santoro

Date of Reply:

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 3/12th'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.

Name of Respondent:
Maureen Heaphy
James Molloy

Date of Reply:
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 Storage, Terminating 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

(S000's)

			Provider Company	Total	Electric	Gas
<u>Explanation of Adjustments:</u>						
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)
5		To adj amount allocated from Company 99 - 25.24%	National Grid USA Service Co.	147.7	122.6	25.1
6		To adjust the electric/gas allocation to 83%/17% respectively	National Grid USA Service Co.	-	(253.6)	253.6
7		To adjust the electric/gas allocation to 83%/17% respectively	All Other Companies	-	236.0	(236.0)
8		To adjust accrual that should have been derived from Co. 36	All Other Companies	(39,203.2)	(32,538.6)	(6,664.5)
		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:
James M. Molloy

Date of Reply:
February 23, 2010

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		<u>Rate Year 2011</u>	
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

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

a)

Expense Type	Expense Type Descr	Business Unit	Bus Unit Descr	Segment Allocation			Grand Total	Business Unit Allocation
				Electric	Gas	Other		
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:

Allen Chieco

Date of Reply:

March 1, 2010

Niagara Mohawk
Storm Deferrals - February 2002 to September 2009 - Cost Summary
RAV-27 B_Attach 1

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	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	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.

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

Case: 10-E-0050

Attachment 3 to NM 44 DPS-41 RAV-27 - Major Storms

Response to PART J.

Sheet 1 of 1

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

Expense Type	Historic Test	Historic Test	Adjusted	Inflation Method	Rate Year 2011	Rate Year 2012	Rate Year 2013	Exhibit RRP-2, RRP-10 Schedule
	Year	Year Adjustment	Year					
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

General - (Exhibit RRP-7)

Historic test year through 2011	3.2%	29,900,643.20	31,312,913.95	31,373,952.77
2012	1.8%	6,647,263.06	24,492,822.05	25,129,635.42
2013	1.9%	23,872,146.25	6,766,913.79	6,895,485.16
		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

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

Case: 10-E-0050

Attachment 3 to NM 44 DPS-41 RAV-27 - Major Storms

Response to PART J.

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.

Niagara Mohawk
Storm Deferrals - February 2002 to September 2009 - Cost Summary
RAV-27 B_Attach 1

Event	Total	Base Pay	Benefits	Bonus	Contractor	Emp Exp	Inventory	Other	Overtime	Sales & Use Tax	Transportation	Payroll Tax	Regional Disqual.	Storm Deduct
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Storm # 82950	576,960		140,024		643,056	100,412	6,075	111,057	1,571,541		4,795			-2,000,000
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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
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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
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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
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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

General - (Exhibit RRP-7)					29,900,643.20	31,312,913.95	31,373,952.77	
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 FY10	FY11	Per FY11 - FY15 Capex/COR Plan			
			FY12	FY13	FY14	FY15
Distribution						
Capex Forecast (Workpaper 3)	129.0	244.0	255.0	265.0	275.0	286.0
COR Forecast						
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
COR Forecast						
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
COR Forecast						
COR Forecast	4.6	10.0	17.3	22.0	22.4	22.4
Shared Services						

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?

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:

Glen DiConza
Antoinette Stores

Date of Reply:

4/1/2010
4/1/2010

Draft budget # - not final

271,000,000

23,886,155 COR Column Total

24,000,000 USED

8.9%

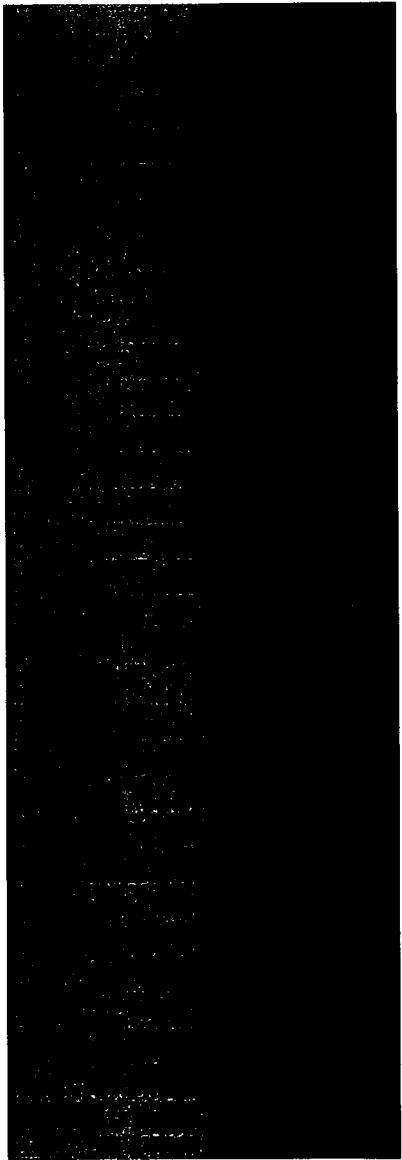
AJR-1 SUPP

Attachment 1

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

C29113	36	Brook Road 36954 Getaway cable repl	NY	NY	DIST	LINE & OTHER	Asset Replacement	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	18,000.00
C24240	36	Battery Strategy FY09 CO36 DxT	NY	NY	DIST	SUB	Asset Replacement	2,500.00
C25639	36	Buffalo Indoor Sub. #23 Refurb.	NY	NY	DIST	SUB	Asset Replacement	13,000.00
C25659	36	Buffalo Indoor Sub. #52 Refurb.	NY	NY	DIST	SUB	Asset Replacement	21,200.00
C25660	36	Buffalo Indoor Sub. #43 Refurb.	NY	NY	DIST	SUB	Asset Replacement	19,000.00
C25801	36	IE - NY ARP Transformers	NY	NY	DIST	SUB	Asset Replacement	30,000.00
C26054	36	NY ARP MetalClad Equipment	NY	NY	DIST	SUB	Asset Replacement	5,000.00
C26760	36	NY Small Capital Items	NY	NY	DIST	SUB	Asset Replacement	2,000.00
C28788	36	Alps - new dist sub - add feeder	NY	NY	DIST	SUB	Asset Replacement	2,000.00
C29205	36	Network Transformer Replacement	NY	NY	DIST	SUB	Asset Replacement	6,000.00
C29206	36	Network Protector Replacement	NY	NY	DIST	SUB	Asset Replacement	6,000.00
C32004	36	Mobile Readiness-NY Central	NY	NY	DIST	SUB	Asset Replacement	4,000.00
C32005	36	Mobile Readiness-NY West	NY	NY	DIST	SUB	Asset Replacement	12,000.00
C32014	36	Batts/Charg- NY West	NY	NY	DIST	SUB	Asset Replacement	7,000.00
C32252	36	NE ARP Breakers & Reclosers	NY	NY	DIST	SUB	Asset Replacement	14,200.00
C32253	36	NC ARP Breakers & Reclosers	NY	NY	DIST	SUB	Asset Replacement	19,400.00
C32261	36	NW ARP Breakers & Reclosers	NY	NY	DIST	SUB	Asset Replacement	12,600.00
C32296	36	Altamont Sub Metalclad Replacement	NY	NY	DIST	SUB	Asset Replacement	17,000.00
C32298	36	Market Hill Sub Metalclad Replacemt	NY	NY	DIST	SUB	Asset Replacement	3,000.00
C32340	36	Ellicott Regulator Replacement	NY	NY	DIST	SUB	Asset Replacement	9,000.00
C33473	36	Buffalo Station 27 Rebuild - Sta	NY	NY	DIST	SUB	Asset Replacement	6,000.00
C33474	36	Buffalo Station 37 Rebuild - Sub	NY	NY	DIST	SUB	Asset Replacement	6,000.00
C33475	36	Buffalo Station 59 Rebuild - Sub	NY	NY	DIST	SUB	Asset Replacement	6,000.00
C26159	36	FH - NE D-Line Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	635,900.00
C26160	36	FH - NC D-Line Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	635,900.00
C26161	36	FH - NW D-Line Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	635,900.00
C26162	36	FH - NE UG Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	83,300.00
C26163	36	NC - UG Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	83,300.00
C26164	36	NW - UG Work Found by Insp.	NY	NY	DIST	LINE & OTHER	Asset Replacement - I&M (NY)	83,400.00
CNC014	36	Cent NY-Dist-Damage/Failure Blanket	NY	NY	DIST	LINE & OTHER	Damage/Failure	676,600.00
CNE014	36	East NY-Dist-Damage/Failure Blanket	NY	NY	DIST	LINE & OTHER	Damage/Failure	925,820.00
CNW014	36	West NY-Dist-Damage/Failure Blanket	NY	NY	DIST	LINE & OTHER	Damage/Failure	854,590.00



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

C28820	36	Park Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	13,020.00
C28825	36	Krumkill Voorheesville Tie	NY	NY	DIST	LINE & OTHER	Load Relief	52,500.00
C28832	36	Bartell 56 Orangeport	NY	NY	DIST	LINE & OTHER	Load Relief	26,250.00
C28837	36	Canajoharie D-Line Work	NY	NY	DIST	LINE & OTHER	Load Relief	94,500.00
C28843	36	Church St 04358 exten.	NY	NY	DIST	LINE & OTHER	Load Relief	14,805.00
C28844	36	Brook Rd 36957 Exten. Adams Road	NY	NY	DIST	LINE & OTHER	Load Relief	49,665.00
C28847	36	Fairdale Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	31,500.00
C28848	36	Mexico Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	21,000.00
C28849	36	Phoenix Load Relief	NY	NY	DIST	LINE & OTHER	Load Relief	21,000.00
C28852	36	Starr 53 Step Down	NY	NY	DIST	LINE & OTHER	Load Relief	52,500.00
C28854	36	Cortland 02 Relief	NY	NY	DIST	LINE & OTHER	Load Relief	10,500.00
C28869	36	E Syracuse 69 Conductor	NY	NY	DIST	LINE & OTHER	Load Relief	6,300.00
C28870	36	Station 21 - Split F2173	NY	NY	DIST	LINE & OTHER	Load Relief	26,250.00
C28929	36	Frankhauser New Station - Line Work	NY	NY	DIST	LINE & OTHER	Load Relief	63,000.00
C29030	36	Batavia 01 - UG Cable Recond.	NY	NY	DIST	LINE & OTHER	Load Relief	105,000.00
C29181	36	Station 79 - F7961 Relief	NY	NY	DIST	LINE & OTHER	Load Relief	15,382.50
C29182	36	Station 79 - F7962 Relief	NY	NY	DIST	LINE & OTHER	Load Relief	19,950.00
C30506	36	N Syracuse Sub Getaways	NY	NY	DIST	LINE & OTHER	Load Relief	3,150.00
C32171	36	Amsterdam 32654 - extension	NY	NY	DIST	LINE & OTHER	Load Relief	42,000.00
C32345	36	Butts Rd. 7252 Extension	NY	NY	DIST	LINE & OTHER	Load Relief	70,875.00
C32350	36	Albion 8064 Getaway Reconductoring	NY	NY	DIST	LINE & OTHER	Load Relief	19,687.50
C32390	36	NW-Batavia Sub Dist. Line Cap Banks	NY	NY	DIST	LINE & OTHER	Load Relief	13,860.00
C32413	36	Tonawanda 4.16 057 Recon UG Getaw	NY	NY	DIST	LINE & OTHER	Load Relief	35,122.50
C32452	36	NW 15564 Fdr, Recond ug getaway	NY	NY	DIST	LINE & OTHER	Load Relief	11,812.50
C32453	36	NW Fdr 4671 Recond UG cable	NY	NY	DIST	LINE & OTHER	Load Relief	19,687.50
C32470	36	NW F3964 Extend ug, Xfer load	NY	NY	DIST	LINE & OTHER	Load Relief	18,900.00
C32494	36	Gilbert Mill Relief	NY	NY	DIST	LINE & OTHER	Load Relief	53,392.50
C32510	36	Brockport Feeder Capacitors	NY	NY	DIST	LINE & OTHER	Load Relief	26,480.00
C32595	36	Rathbun Labrador conversion	NY	NY	DIST	LINE & OTHER	Load Relief	15,750.00
C32598	36	Ogden Brook - Install new feeders	NY	NY	DIST	LINE & OTHER	Load Relief	10,500.00
CNC016	36	Cent NY-Dist-Load Relief Blanket	NY	NY	DIST	LINE & OTHER	Load Relief	43,575.00
CNE016	36	East NY-Dist-Load Relief Blanket	NY	NY	DIST	LINE & OTHER	Load Relief	21,735.00

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

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

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

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

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

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

Transmission 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%
	<u>3,864,762</u>	<u>50,900,000</u>	<u>7.6%</u>

2008	COR	Total Spend	%
TxT	4,980,541	62,800,000	7.9%
	<u>4,980,541</u>	<u>62,800,000</u>	<u>7.9%</u>

2009	COR	Total Spend	%
TxT	5,133,616	69,425,248	7.4%
	<u>5,133,616</u>	<u>69,425,248</u>	<u>7.4%</u>

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

COR	MAT %											
	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:
IOP panel / Sara Sankowich

Date of Reply:
March 1, 2010

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

	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
\$'000														
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	1,887,780
Worst Feeders						914,478		117,508	424,401	-	630,492	649,407	668,889	888,956
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	2,068,006	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	198,284
Other Veg Costs - All Other		2,612,140		2,361,311		2,318,032		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 [$\$10,300,000 / \$110,000,000$]

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:

Shannon Larson & Stephen Adams

Date of Reply:

March 3, 2010

Niagara Mohawk Power Corporation
d/b/a National Grid
Case 10-E-0050
Attachment 1 to RAV-33

	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:

- 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.

FY11 Capital Budget:

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.

Name of Respondent:

Infrastructure and Operations Panel/Rob Sheridan

Date of Reply:

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.

Name of Respondent:
Mark Eddy

Date of Reply:
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 Draft 5-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	66,645,000	
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	6,696,000
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

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

	FY06 Proposed Budget		FY06 Actuals	FY07 Proposed Budget		FY07 Actuals	FY08 Proposed Budget *		FY08 Actuals *	FY09 Proposed Budget *		FY09 Actuals *	FY10 Proposed Budget *		FY10 Forecasted Actuals *
DISTRIBUTION															
Asset Condition	xx	xx	xx	xx	xx	xx	32.6		31.6	41		41.0	50.9	43.9	46.7
Damage Failure	xx	xx	xx	xx	xx	xx	15.4		15.4	16.1		16.1	20.3	22	21.0
Other/Non-Infrastructure	xx	xx	xx	xx	xx	xx	1.9		1.9	(2.0)		(15.8)	2.1	4.2	2.8
Statutory/Regulatory	xx	xx	xx	xx	xx	xx	118.1		118.1	105.6		101.9	96.6	118.6	118.2
System Capacity & Performance	xx	xx	xx	xx	xx	xx	38.1		38.1	42.6		69.9	69.9	55.5	53.4
Total	135.5	135.5	160.4	169.5	169.5	182.1	206.1		194.0	213.1		213.1	216.3	244.2	242.1
SUB-TRANSMISSION															
Asset Condition	xx	xx	xx	xx	xx	xx	20.2		20.2	21.3		22.7	19.2	26.4	25.0
Damage Failure	xx	xx	xx	xx	xx	xx	1.3		1.3	2.2		1.9	3.9	2.1	3.3
Other/Non-Infrastructure	xx	xx	xx	xx	xx	xx	-8.9		(8.9)	-		-11.8	(11.8)	-5.9	(1.0)
Statutory/Regulatory	xx	xx	xx	xx	xx	xx	2.5		2.5	(0.9)		6.7	6.7	9.3	7.6
System Capacity & Performance	xx	xx	xx	xx	xx	xx	2.9		2.9	3.8		8.5	8.5	6.1	6.4
Total	8.2	8.2	12.3	27	27.0	23.8	18		18.0	28		28.0	31.4	38	41.3
TRANSMISSION															
Asset Condition	xx	xx	xx	xx	xx	xx	12.2		12.2	15.1		22.7	22.7	16.9	49.2
Damage Failure	xx	xx	xx	xx	xx	xx	6.3		6.3	11.9		21.6	21.6	15.1	10.4
Other/Non-Infrastructure	xx	xx	xx	xx	xx	xx	1.3		1.3	0.3		(10.1)	0.6	3.4	6.2
Statutory/Regulatory	xx	xx	xx	xx	xx	xx	30.6		30.6	24.5		37	37.0	52.9	22.6
System Capacity & Performance	xx	xx	xx	xx	xx	xx	9.5		9.5	10.4		10.5	10.5	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	97	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
Due Date: March 8, 2010

Request No. AJR-3
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:
Mark Eddy

Date of Reply:
March 8, 2010

IS Investment Planning

AJR-3, Exhibit 1

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)

	FY06 Actuals		FY07 Actuals		FY08 Actuals		FY09 Actuals		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)

	FY06 Actuals		FY07 Actuals		FY08 Actuals		FY09 Actuals		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

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:

James Molloy

Date of Reply:

March 9, 2010

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

		Data		
2 - Parent Level Rev	3 - Parent Level Rev			
Electric Dist & Gener	CFO Dist & Generation	66		66
	Chief Oper Officer-Elec Dist	5,800		5,800
	Customer Markets	2,365	77	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	17,763

Niagara Mohawk Power Corporation
d/b/a National Grid
Case 10-E-0050
Attachment 1 to RAV-40
Sheet 2 of 2

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

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:

James Molloy

Date of Reply:

March 16, 2010

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:
James Molloy

Date of Reply:
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?”
 - 5.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:

James M. Molloy and Stephen Heywood

Date of Reply:

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/padmouted, 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.

Name of Respondent:

Brian V. Hayduk

Date of Reply:

March 7, 2010

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

	ACTUAL QTY REPLACED				TARGETED QTY TO REPLAC			
	FY07	FY08	FY09	FY10 (YTD)	FY11	FY12	FY13	
1-phase & 3-phase OVERHEAD	133	231	469	361	<i>(determined on an annual basis- response to question 1)</i>			
1-phase UNDERGROUND	0	3	10	6				
3-phase UNDERGROUND	0	0	2	0				
TOTAL	133	234	481	367	639	1,278	2,109	

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:

Susan F. Tierney

Date of Reply:

March 8, 2010

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 nual 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:

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:

Susan F. Tierney

Date of Reply:

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

Date of Request: March 1, 2010

Request No. CLG-2

Due Date: March 11, 2010

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?

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:
Pamela B. Dise

Date of Reply:
June 17, 2010

SC3 Customers with Average Demand between 250kW and 499kW

	(A)	(B)	(C)	(D)
	<u>Total Annual kWh</u>	<u>Bill Accounts</u>	<u>Exisitng Interval Meters</u>	<u>Interval Meters Needed</u>
1 Retail Access	1,402,108,107	837	245	592
2 Full Service	490,970,602	342	119	223
3 Total	<u>1,893,078,709</u>	<u>1,179</u>	<u>364</u>	<u>815</u>
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:
Peter Zschokke

Date of Reply:
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.

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

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:
Dawn Travalini

Date of Reply:
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/Industrial	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

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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
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/Indust	4321	5323127	Trim, prune tree	34.5
5310251	7	0.24	Commercial/Indust	4210	5323130	Trim, prune tree	34.5
5369332	14	0.95	Commercial/Indust	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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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
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

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System Id	Site Number	Site Area (Acres)	Land Use	Land Use Code	Forestry Segment	Prescription	Voltage
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

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
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

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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/Industri	4000	5241806	Trim, prune tree	46
5237721	19	0.15	Commercial/Industri	4131	5241862	Trim, prune tree	46
5237834	5	0.77	Commercial/Industri	4000	5241866	Trim, prune tree	46
5240467	25	0.61	Commercial/Industri	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

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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

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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/Indust	4112	4462151	Trim, prune tree	115
5369027	331	0.93	Commercial/Indust	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

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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/Industrial	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

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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/Inc	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

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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
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

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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
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

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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
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

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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
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

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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

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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

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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

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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
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

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
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

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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
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

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
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

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
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

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				

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Projected CY2013 Floor Trim Acres

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System Id	Site Number	Site Area (Acres)	Land		Forestry Segment	Prescription	Voltage
			Land Use	Use Code			
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

NM 123 DPS 88 DSM-4

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		Forestry Segment	Prescription	Voltage
			Land Use	Use Code			
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

NM 123 DPS 88 DSM-4

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

Transmission Spend FY06 through FY10

NM 167 DPS 97 VVP-3
Attachment 1

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 safety	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
		Battery Rpl Strategy Co36 Txt	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 Teal 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	C29644				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	821,120	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	1,676,667	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	9,631,816	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-HH 151-152, T1950-T1280 N ACR	C04718	587,868	564,226	165,934	388,639	8,244,389	9,950,955	4,255,611	14,206,586	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-Batavia 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
	Lockport-Mort 111 Tap T1530-1 Refurb	C33014									39
	Mortimer - Pannell Road #24	CNYAS65									40
	Pannell-Genève 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 replacement 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
	Yahundasis - 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	11,082	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 V1. 8	C28676			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

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

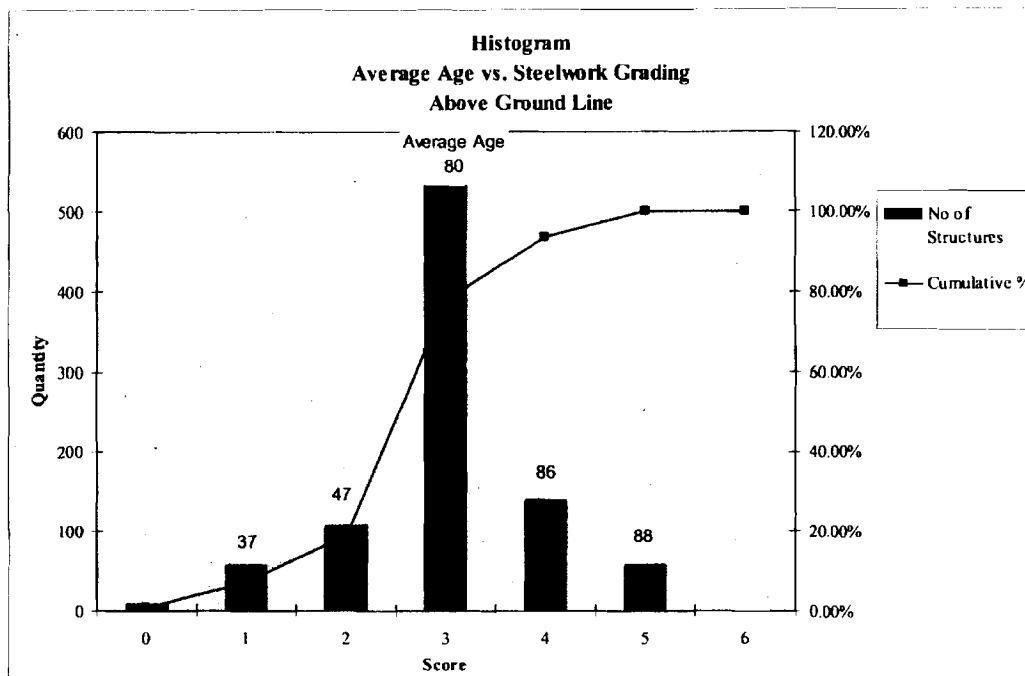
Request:

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?

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 properly¹ applied painting system could extend the life of steel structure with rust by 10 years². 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 years³ (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 structures⁴, 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:
Art Peterson

Date of Reply:
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 at Attachment 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.

Name of Respondent:
Melissa Little/Avron Segal

Date of Reply:
March 17, 2010

INVP 1022

*CTA Funded Sheets 38 & 39
1 of 2*

Confidential

**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)

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Ref. No. XXX

- 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
1042

Confidential

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
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.

Name of Respondent:
Antoinette Stores
Legal Department

Date of Reply:
May 19, 2010

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 / Strategy Date	Confidential (Y/N)	Risk Score	FY11	FY12	FY13	FY14	FY11-14		
Transmission	Clay Station Rebuild	C32339	Clay Station Line Project	Open	N/A	SG095	Yes	48	0.1	2	2	0	4.1		
		C31141	Dawgo Lafayette 17, T2420 CCR	Open	N/A	SG02943	No	33	0.3	2	2	0	4.1		
		C03265	Transmission Tower Clearances	Open	N/A	SG02943	No	40	0.5	0	0	0	0	0.5	
			Clearance Strategy Total						40	1	15	15	15	45	
Digital Fault Recorder Strategy	Digital Fault Recorder Strategy	C03726	Digital Fault Recorder Strategy	Open	AMIC07133 AMIC07121 AMIC0775 AMIC0749 NTSC0659 NTSC0658 NTSC0659 NTSC0655 AMIC0983 AMIC0986 AMIC0832 AMIC08104	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, 2011	Yes	49	1.1	0	0	0	0	1.1	
		C28487	Repl DFR at Non-BPS Stations	Open	N/A	N/A	N/A	27	0	0	0	0	0	0	
			Digital Fault Recorder Strategy Total						27	1.1	0	0	0	1.1	
		Generation	Generation	CNYX63	Alabama Ledge Wind-Loop in, Loop-out	N/A	N/A	Study Attached	Yes	49	0.2	0.2	0	0	0.4
				CNYX63R	Alabama Ledge Wind-Loop in, Loop-out	N/A	N/A	Study Attached	Yes	49	-0.2	-0.4	0	0	-0.5
				CNYX64	Alabama Ledge Wind-RTU/Metering/Relay	N/A	N/A	Study Attached	Yes	48	1	0.7	0	0	1.6
				CNYX64R	Alabama Ledge Wind-RTU/Metering/Relay	N/A	N/A	Study Attached	Yes	48	-1	-0.7	0	0	-1.6
				CNYX01	Alabama Generation Expansion—Permanent	N/A	N/A	N/A	N/A	1	6	10.4	25.5	26.1	68
				CNYX01R	Alabama Generation Expansion—Permanent	N/A	N/A	N/A	N/A	1	-6	-10.4	-25.5	-26.1	-68
				CNYX02	Alabama Generation Expansion—Permanent	N/A	N/A	N/A	N/A	1	0	0	0.5	3.4	3.9
				CNYX02R	Alabama Generation Expansion—Permanent	N/A	N/A	N/A	N/A	1	0	0	-0.5	-3.4	-3.9
				C23413	BEDCO Substation Work	Open	AMIC07164	Open	N/A	December 21, 2007	Yes	49	0.1	0	0
CNYX60	Cape Vincent Wind-RTU/Metering/Relay			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			N/A	N/A	N/A	N/A	N/A	48	-0.1	-2.7	0	0	-2.8	
CNYX70	Clayton Wind-Loop in, Loop-out			N/A	N/A	Study Attached	Yes	April 30, 2007	Yes	49	0.4	2	0	2.4	
CNYX70R	Clayton Wind-Loop in, Loop-out	N/A	N/A	Study Attached	Yes	April 30, 2007	Yes	49	-0.4	-2	0	-2.4			
CNYX71	Clayton Wind-RTU/Metering/Relay	N/A	N/A	Study Attached	Yes	April 30, 2007	Yes	48	0.3	1	0	1.3			
CNYX71R	Clayton Wind-RTU/Metering/Relay	N/A	N/A	Study Attached	Yes	April 30, 2007	Yes	48	-0.3	-1	0	-1.3			
C39643	Fairfield Wind Farm Interconnection	Open	AMIC07178	Open	N/A	July 9, 2008	Yes	49	0.8	0	0	0	0.8		
C28543R	Fairfield Wind Farm Interconnection	Open	AMIC07178	Open	N/A	July 9, 2008	Yes	49	-0.8	0	0	0	-0.8		
C29782	Fairfield Wind-Loop in loop out	Open	N/A	Open	N/A	N/A	N/A	49	1	0	0	0	1		

	C28782R	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,metring	N/A	AMIC0961	N/A	August 2, 2009	Yes	49	1	0	0	0	1
	CNYX69R	Green Power-Cody Rd-RTU,metring	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/metring/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/metring/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	February 14, 2008	Yes	49	0.4	0.4	0	0	0.8
	CNYX65R	New Grange Wind-Loop in, Loop-out Reimbursable portion	N/A	N/A	Study Attached	February 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	February 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	February 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 - Reimbursable Portion	Open	AMIC07152	N/A	October 17, 2007	Yes	49	-0.1	0	0	0	-0.1
	CNYX67	Sherman Island Upgrade- RTU/Metering/Relay upgrades	N/A	AMIC08120	N/A	January 19, 2009	Yes	49	0.8	0	0	0	0.8
	CNYX67R	Sherman Island Upgrade- 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 Reimbursable 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/metring	N/A	AMIC07179	N/A	January 9, 2008	Yes	49	0.6	0	0	0	0.6
	CNYX50R	WestHill Wind-RTU/metring Reimbursable Portion	N/A	AMIC07179	N/A	January 9, 2008	Yes	49	-0.6	0	0	0	-0.6
		Generation Total							0.1	0	0.4	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 -Reimbursable Portion	Open	N/A	SG101	September 11, 2008	Yes	49	-0.1	-0.2	0	0	-0.3
		Load Total							0.6	2	2	2	6.9
Luther Forest	C22738	Luther Forest Relay and Malta Sub work	Open	AMIC0958 - TIC0916	SG060, SG097	October 21, 2008	Partial	49	3.4	4.6	0	0	8.2
		Luther Forest Total							3.4	4.6	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	11.6	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
	CNYX38A	Rotterdam Banks - Part of NERR	N/A	N/A	SG097	February 17, 2008	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, 2008	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	7.6	0.1	9.6
		Northeast Region Reinforcement Total							7.4	41.2	66	38.6	181.9

	Other Statutory/Regulatory	C28463	Repl 23 meters Interconnect/ NYISO	Open	N/A	SG127	January 8, 2010	No	48	0.8	2	1.8	1.4	5.9
		C32551	Various Station - Range Operations	Open	N/A	Study Attached	September 7, 2007	Yes	48	0.1	0	0	0	0.1
Other Statutory/Regulatory Total														
	RTU Strategy	C03772	RTU Replacements NERC, EMS, Obsolescence	Open	NTSC0585 NTSC0655 AMIC07129 AMIC0850 AMIC0855 AMIC08119 AMIC08106 AMIC0938 AMIC0970	SG002v2	May 27, 2008 August 18, 2005 July 17, 2006 September 10, 2007 June 2, 2008 July 22, 2008 December 22, 2008 February 5, 2010 October 1, 2008	Mixed	49	1.5	2	1.4	0	4.9
RTU Strategy Total														
	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	9.6	6	11	0	28.8
Station Upgrades Total														
	Reserve	CNYX32	Reserve	Reserve	Reserve	Reserve	Reserve	Reserve	48	-3.2	-10.7	-11.2	-6.6	-31.7
Reserve Total														
Transmission Total														
Total Statutory/Regulatory														
										156.8	230.8	255.5	207.8	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	April 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	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 & Post Cldg	Open	N/A	PIW-128-2007	6/29/2007	No	16	0.2	0	0	0	0.2
		C32596	Porter Sub - Repl. Barre Repl. & 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
		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
		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

Transmission--System Capacity and Performance

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 220kV 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 eye	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 - Reimbursement	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/TVRV	N/A	N/A	N/A	N/A	n/a	33	0	0	0.3	0.7	1
	C30806	Install new Alps Site Substation	Open	N/A	N/A	N/A	n/a	27	1.1	0.8	0	0	1.9
	C33619	Install new Alps Site Substation 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 115kV Switchgear	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 Breaker	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 Completion		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- part of SG077	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 #180 part of	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	Reconductorin g of #171, part of SG075	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 of SG077	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 capability of L107, part of SG077	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	Reserve	Reserve	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/B Tower Strategy	C06017	Leeds - Pleasant Valley 91/92 Tower Reinforcement - includes public safety	Open	N/A	SG032,SG080	No, No						
		C07918	New Scotland - Leeds 93/94 Tower Reinforcement - Public Safety	Open	N/A	SG032	No	49	0	0	0.1	0.1	0.2
3A/B Tower Strategy Total													
Battery Strategy		C24239	Battery Strategy FY09 Co. 36 Tr	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	Battery Rpt/Strategy Co. 47	Open	N/A	SG128	No	39	0.6	0.6	0.6	0.6	2.5
Battery Strategy Total													
Circuit Breaker Replacement Strategy		C31661	Inghams-replace 115kv OCB	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A						
		CNYAS24	Meco - Replace 115kv PTs and circuit breakers	N/A	N/A	Please refer to January 2010 CIP Filing for	N/A	35	0.1	0.2	1	5	6.3
		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	8	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											
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													
Other Asset Condition		C28304	Alps #188 Obsolete Circuit Switches	Open	N/A	N/A	N/A	16	0.2	0.7	0	0	0.9
		C27082	Ash 10 Yearly Cathodic Protection Upgrade	Open	N/A	N/A	N/A	28	0	0.1	0	0	0.1
		C31005	Bristol Hill Repl SWs #6 & 47	Open	N/A	TS0720081367 TS0720081368	No, No	28	0	0.2	0	0	0.2
		C31950	Butler Sta 64 -RPL #1382	Open	N/A	PIW 062-2007	No	43	0.6	0	0	0	0.6
		C29444	Colton Replace CBe and disconnects	Open	N/A	N/A	N/A	34	0.6	0.9	0.9	0	2.8
		C31967	Dewitt-Rebuild 345kv	Open	AMC0913	N/A	No	49	0.3	0	0	0	0.3
		C27845	Dumont 230kV Control Cable TB1	Open	AMC0951	N/A	No	34	0.6	0	0	0	0.6
		C31025	Edic Station - Replace TB2, 3, 4 Metering	Open	N/A	TS820081404	No	40	0	0.1	0	0	0.1
		C03383	EJ West-Wernersburg 9 115kV Cross Braces	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 Furne dated 11/29/2007 Email	No	35	0	0.1	0	0	0.1
		C03384	Elmore 115kV Tap Cross Braces	Open	N/A	N/A	N/A	16	0	0	0	0.1	0.1
		C03261	Fenner-Cortland 3 Cross Braces	Open	N/A	N/A	N/A	21	0	0	0	0.1	0.1
		C27829	Gardenville Control Cable	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 Furne dated 11/29/2007 Email	No	36	0	0.1	0	0	0.1
		C31004	Gibson Sta - Repl SW1802.03	Open	N/A	TS0620081338 TS720081389	No, No, No	28	0.1	0.3	0.3	0	0.6
C31663	Greenbush - Replace TB1	Open	N/A	N/A	N/A	38	0	0.6	1	0	1.6		

	C29950	Harper Station - Replace 2023 & 2033 MCR	Open	N/A	TS0420081278	No	22	0	0.1	0.3	0	0.5	
	C30531	Huntley Station - HPIFF Alarming	Open	N/A	PIW from Len Flume dated 11/29/2007 Email	No	35	0	0.1	0	0	0.1	
	C28044	Lafayette - Replace Line A Relays	Open	AMIC08127	N/A	Yes	35	0.1	0	0	0	0.1	
	C03748	Leeds SVC - Refurbishment/Replacement	Open	AMIC0899-TIC0923	SG059	Yes (AMIC Paper), NO (SG059)	38	5.9	0	0	0	5.9	
	C27042	New Gardenville TBS AT&M	Open	N/A	SG113	No	34	3.7	0	2.8	2.8	9.3	
	C31858	NY Surge Arrester Replacement	Open	N/A	No Strategy required, refer to SMP	No	36	0	0	2.7	2.6	5.3	
	C28216	Oswego - Replace Special	Open	N/A	TS920081420	Yes	35	0	0.7	0	0	0.7	
	C27008	Packard Replace TBS AT&M	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 230V Breakers	Open	N/A	N/A	N/A	28	0.5	0.4	0	0	0.9	
	C30532	Rochester Generator and HPIFF Alarms	Open	N/A	PIW from Len Flume dated 11/29/2007 Email	No	38	0	0.1	0	0	0.1	
	C15988	Rochester HPIFF Cable Bus	Open	N/A	N/A	N/A	44	0	0	0.9	0.1	1.1	
	C29948	Rochester Pump LPIFF Trip Scheme	Open	N/A	PIW from Len Flume dated 11/29/2007 Email	No	35	0	0	0.4	0	0.4	
	CNYA538	Silver Creek switch structure - replace 115M Disconnect	N/A	N/A	N/A	N/A	21	0	0	0	0.3	0.3	
	C31044	Taylorville Rapi 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	26	0	0	0	0	0	
	C32308	Ticonderoga-Sentford T&M 108 Relays	Open	N/A	TL0520081301	No	43	0	0.1	0.2	0	0.2	
	C11318	Trinity US Pumphouse Redesign	Open	N/A	N/A	N/A	49	0.7	0.3	0	0	1	
	C29961	Youngmann Terminal Station - Replace Switch #310	Open	N/A	TS0420081285	No	19	0.1	0	0	0	0.1	
	Other Asset Condition Total								21.8	6.5	15	8.1	48.3
	Overhead Line Refurbishment Program	CNYA562	Dunkirk - Falconer #161	N/A	N/A	SG080	No	40	0	0	0.1	0.1	0.2
		CNYA549	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, T1280-1270 ACR	Open	N/A	SG080	No	44	0.5	0	27	15	51.5
		CNYA560	Gardenville - Buffalo Sw #148 (146)	N/A	N/A	SG080	No	16	0	0	0.1	0.1	
		CNYA575	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	30	0.1	0.1	1	1	2.2
		C27436	Gardenville Lines 180-182, T1860-T1780 ACR	Open	N/A	SG080	No	44	0.1	0.1	0.1	12.5	12.7
		C04718	Gard-HH 151-152, T1950-T1280 ACR	Open	AMIC08117-TIC 0919	SG080	No, No	49	8.8	8.7	0	0	16.6
		C27429	Home - HB Bennett Rd 157, T1340 ACR	Open	N/A	SG080	No	39	0.1	0.1	0.1	0.1	0.3
		CNYA553	Huntley - Lockport #37	N/A	N/A	SG080	No	44	0.1	0.1	0.1	0.1	0.3
		CNYA551	Huntley - Praxair #46	N/A	N/A	SG080	No	18	0	0.1	0.1	0.1	0.3
		CNYA563	Huntley-Gardenville 38 (A, 38) (refurb)	N/A	N/A	SG080	No	40	0	0	0	0.1	0.1
		CNYA556	Index Oswego - Lockhouse Hill #2	N/A	N/A	SG080	No	39	0.1	0.1	0.1	6	6.2
		C27432	Lockport 103-104, T1430-T108 STD	Open	N/A	SG080	No	40	0.1	0.1	0.1	0.1	0.3
		C03417	Lockport Morimer 111, T1330 ACR	Open	N/A	SG080	No	49	1.6	1.2	21	12	48.6
		C03422	Lockport-Batavia 112, T1510 ACR	Open	N/A	SG080	No	39	0	0.2	2.5	12.3	15
		C27431	Lockport-Batavia 108 Refurb	Open	N/A	SG080	No	29	0	0.1	0.1	0.1	0.2

	C19670	Lockport-Mort 113-114, T1540-T1550	Open	AMIC0984-TIC 0918	SG080	No, No	49	1.8	0	0	0	1.8	
	C33014	Lockport-Mort 111 Tap T1530-T1540	Open	N/A	SG080	No	39	0	0.1	0.3	0	0.4	
	CNYAS85	Mortimer - Pannell Blvd #24	N/A	N/A	SG080	No	40	0	0.1	0.1	0.1	0.2	
	C30889	Pannell-Geneva 4-4A, T1560 ACR	Open	N/A	SG080	No	37	0.1	0.4	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, T1420 ACR	Open	N/A	SG080	No	45	0.1	0.1	0.1	9.9	10.2	
	C27437	Taylorville -B 5-6 T3120-T3330 ACR	Open	N/A	SG080	No	35	0.1	0.1	0.6	5.4	6.2	
	C24361	Taylorville-Mosher 7, T3340 ACR	Open	N/A	SG080	No	42	2.4	3.5	0	0	5.9	
	CNYAS82	Tioonderoga Lines 2 (& 3) (Complete Line)	N/A	N/A	SG080	No	40	0	0	0.1	1	1.1	
	C19530	Tioonderoga-2-3, T5810-T5930 SKR	Open	AMIC08107-TIC0818	SG083v1d	No, No	48	3.2	0	0	0	3.2	
	Overhead Line Refurbishment Program Total								29.2	32.6	63.7	82	199.4
Relay Replacement Strategy	CNYAS29	Browns Falls - protection replacement and new control building	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	Geras 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	0.6	3.5	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								8.4	1	3.8	6.8	11.2
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	Oneds - 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	Sheldons Buffalo 145	Open	N/A	SG073	No	40	0.3	1.3	0	0	1.6	
	C28709	Sheldons Clay-Depew 3	Open	AMIC0910-TIC0905	SG073	Yes (AMIC Paper) No (SG073)	40	1.2	1.2	0	0	2.4	
	C28708	Sheldons 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
	C28678	Shieldwire: Hundley - Gardenville	Open	AMIC0894	SG073	No, No	40	1.5	0	0	0	1.5
	C28707	Shieldwire: Hundley - Lockport 36/37	Open	AMIC0895	SG073	No, No	40	1.5	0	0	0	1.5
	C28678	Shieldwire: LaFarge Pleasant VA #	Open	AMIC0873 - T/C0812	SG073	No, No	40	1.7	0	0	0	1.7
	C28681	Shieldwire: Mountain - Lockport 11A	Open	AMIC08100	SG073	No, No	40	1.3	0	0	0	1.3
	C28712	Shieldwire: Walck Rd - Hundley	Open	AMIC0896	SG073	No, No	40	0.6	0	0	0	0.6
	Shield Wire Strategy Total							8.2	7.2	0	0	15.4
	Steel Tower Strategy	C21893	S. Oswego Lighthouse Hill Circuits	Open	N/A	SG18V2 SG29V2c Spans	No, No, No	49	4.5	0.4	0	4.9
	Steel Tower Strategy Total							4.9	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
		C05155	Dunkirk Rebuild	Open	N/A	Please refer to January 2010 CIP Filing for details	N/A	35	0	0	0.1	0.5
		CNYAS91	Elm St. Refurbishment	N/A	N/A	N/A	N/A	35	0	0	0.5	1
		C05156	Gardenville Rebuild	Open	N/A	SG112	Yes	35	0.5	2.7	36.4	23
		C30084	Gardenville Rebuild	Open	N/A	SG112	Yes	44	1	1.2	1.3	0.1
		C31602	Lights 115kV Yard Bays & cold bus	Open	N/A	N/A	N/A	35	0.3	1	5	5
		CNYAS2	Lockport Rebuild	N/A	N/A	N/A	N/A	35	0	0	0.2	1
		CNYAS44	Mohican - rebuild including transformers and oil circuit breakers	N/A	N/A	N/A	N/A	35	0.1	0.2	1	10
		C29180	N. Leroy Rebuild Station	Open	N/A	N/A	N/A	34	0.1	0	0	0
		CNYAS38	Porter 230kV - replace disconnects and PTs	N/A	N/A	N/A	N/A	28	0	0.3	1	10
		CNYAS27	Reynolds Road - protection replacement & new control building & replace Overduty 115kV Breakers	N/A	N/A	N/A	N/A	19	0	0	0.5	1
		C03778	Rome 115 kV Station	Open	N/A	SG123	No	22	0.4	2	8.7	2.1
		C17848	Rotterdam R/R 230kV EPE RUF CBs	Open	N/A	N/A	N/A	38	0.5	1.6	4	15
	Substation Rebuilds Total							2.8	8.8	58.8	68.8	138.4
	Transformer Replacement Strategy	C31656	NY 115kV Transformer Replace (Priority 4)	Open	N/A	Please refer to January 2010 CIP Filing for details	N/A	41	4	7	7	25
	Transformer Replacement Strategy Total							4	7	7	7	25
	U-Series Relay Strategy	C24662	Edic FE1 - Replace U Series Relay	Open	N/A	SG012	Yes	33	0.3	0	0	0
		C24663	Leeds - Replace U Series Relay	Open	N/A	SG012	Yes	33	0.2	0.7	0	0
		C24661	LNI1 - Replace Type U Relay	Open	N/A	SG012	Yes	33	1.4	0	0	0
		C05150	Westinghouse U Series Relay Strategy	Open	N/A	SG012	Yes	33	0.5	0	0	0
	U-Series Relay Strategy Total							2.5	8.7	0	0	0
	Reserve	CNYX31	Reserve	Reserve	Reserve	Reserve	N/A	48	-9	-9.2	-14.1	-18.8
	Reserve Total							-9	-9.2	-14.1	-18.8	-48.8
	Transmission Total							56.2	67.8	128	187	429.7
	Total Asset Condition							114.2	122.9	183.7	200.8	609.9

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	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:

	<u>Row</u>	<u>Run Rate</u>	<u>Day N</u>
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

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 $\frac{1}{4}$ 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 be 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.

Name of Respondent:

James M. Molloy and Stephen Heywood

Date of Reply:

March 21, 2010

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

List of Initiatives

Initiative Code	Initiative	DAY N \$(000)'s	Included on tab WPI
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 Benefits	\$4,191.2	Yes
Additional Synergies	Alignment of Pension Assumption	\$6,500.0	Yes
Total Additions		<u>\$36,592.3</u>	Yes
Negative Synergy	Reservoir Woods	(\$11,500.0)	Yes
Total Replacement Savings	Currently being included against \$200m target	<u>\$25,092.3</u>	Yes
Potential Synergies	Transaction Delivery Centre	\$16,315.0	No
Grand Total	Total potentially contributing to \$200m target pending HoF's approval	<u>\$41,407.3</u>	Total

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

Initiative Code	Initiative	Fiscal Savings to Date (in thousands)			Aggregate Run Rate (in thousands)			DAY N \$	Adjusted Calculation	Original Calculation
		Sep 08	Mar 09	Sep 09	Sep 08	Mar 09	Sep 09			
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		\$874.0	\$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/Pnning 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
Add Back Finance total which was not included in original calculation
Adjustment to Total
% Allocated to NiMo
Total Adjustment

(4,323.92)
1,580.51
(2,743.41)
24.93%
(684)

Alternate Methodolgy based on Run Rate Calculations
Original Total filed in rate case
Alternate Adjustment
% Allocated to NiMo
Total Adjustment

\$64,703.6 \$128,773.9 \$140,454.9

117,347.8
113,657.7
3,690.08
24.93%
920

Date of Request: March 4, 2010

Request No. WEL-3

Due Date: March 15, 2010

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.

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.