TRANSMISSION AND DISTRIBUTION CAPITAL INVESTMENT PLAN

CASE 06-M-0878

PREPARED FOR:

THE STATE OF NEW YORK PUBLIC SERVICE COMMISSION

THREE EMPIRE STATE PLAZA

ALBANY, NY 12223

JANUARY 29, 2010

nationalgrid

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I. EXECUTIVE SUMMARY

Niagara Mohawk Power Corporation d/b/a National Grid ("The Company" or the "Company") submits its Five Year Capital Investment Plan (the "Plan") in compliance with the requirement of the New York Public Service Commission ("PSC" or "Commission") in its August 15, 2008 Order (the "August 15 Order") in Case 06-M-0878. In that order, the Commission directed The Company to "provide additional details and justifications for projects in its subsequent five year investment Plan filings."[1] The Company was directed to file its five year Plan annually. In meetings with PSC staff, The Company agreed to provide the Plan on January 31st of each year.

The August 15 Order concluded a Commission review of the Company's compliance filing required in the Order issued September 17, 2007 in Case 06-M-0878. The Commission required The Company to:

- file for Commission review and approval the approximately $1.47 billion transmission and distribution ("T&D") capital investment plan described in The Company's testimony in that proceeding;
- detail in the filing the projected expenditures separately for transmission and distribution projects; and
- address in the filing the continued reasonableness of the expenditures in light of the continued inflation in construction and equipment costs.

The Company submitted its first T&D investment compliance filing on October 22, 2007. However, in its August 15 Order, the Commission found the investment plan for 2008 contained specific projects which could be reviewed but that later years did not have a level of detail from which the Commission could ascertain the reasonableness of the investment plan. With respect to the 2008 calendar year expenditures, the Commission's analysis did not find any projects that were unreasonable or unnecessary. The Commission recognized that a long-term forecast of five years will have greater specificity in the early years of the plan but the latter years would not be specific due to circumstances and information changing over time. As such, the Commission ordered the Company to file its five year Capital Investment Plan annually.

The Company filed its Capital Investment Plan for the fiscal years (FY) 2010 through 2014 on January 31, 2009. Although the plan showed investment levels for a period two years beyond the original filing in 2007, PSC Commission and Staff have expressed concern regarding the rate of growth in investment compared to the 2007 plan. The Company and PSC Staff have held numerous discussions on this topic in which the PSC Staff expressed additional concern regarding the size of the investment plan, its impact on customers through rates and the state of economic conditions currently.

[1] Case 06-M-0878, "Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and Other Regulatory Authorizations," Order Concerning Transmission and Distribution Capital Investment Plan, August 15, 2008, Ordering Paragraph No. 2, p. 12.

A. Capital Investment Plan Background

The Company developed this and previous investment plans to meet its obligation to provide safe, reliable, efficient, and environmentally sound electric delivery service to 1.6 million customers at reasonable cost. Providing this service requires the Company to maintain a vast physical infrastructure located in 450 cities and towns across 25,000 square miles. This infrastructure includes 6,000 miles of transmission line, 313 transmission substations, more than 3,400 miles of over head sub-transmission lines on 64,000 towers/poles and about 1100 miles of underground sub-transmission circuits. These assets serve 441 distribution substations which supply a distribution system that consists of more than 800 power transformers, 4,000 breakers, 35,900 circuit miles of primary on over 1,200,000 poles and 442,000 line transformers and 6,900 underground primary circuits.

The Company's five-year plan for investment is $2.86 billion to improve its infrastructure as shown in Table I-1. The Company plans to spend $424 million in fiscal year 2011 ("FY11"), $536 million in FY12, $613 million in FY13 and $635 million in FY14 and $653 million in FY15.

Table I-1
Capital Investment Plan by System ($millions)

System	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	TOTAL
Transmission	132.0	228.0	290.0	295.0	295.0	1,240.0
Sub-transmission	48.0	53.0	58.0	65.0	72.0	296.0
Distribution	244.0	255.0	265.0	275.0	286.0	1,325.0
Total	424.0	536.0	613.0	635.0	653.0	2,861.0

The proposed spending is significantly lower than the investment plan submitted last year, which estimated total spending at $3.57 billion for the five-year period FY10 to FY14. In contrast, the current plan totals $2.86 billion for the five-year period FY11 to FY15, despite adding a year to the plan (FY15). This reduction represents the Company's evaluation and adjustment of spending based on changed circumstances and new information, so that customer needs are met in the most effective and cost-efficient manner possible. In particular, the current economic conditions facing customers in New York requires identifying opportunities to defer or minimize spending where possible, consistent with the Company's obligation to continue to provide safe and reliable service. Thus, the infrastructure investment plan reflected in this case is designed to lessen rate impacts on customers while mitigating significant risks on the system.

Despite this reduction, the Company will exceed its $1.47 billion spending commitment. As shown in Table I-2, the Company's cumulative investment from January 1, 2007 through to December 31, 2009 was $906 million. This exceeds the commitment through 2009 by almost $80 million. Based on the plan filed herein, the Company expects to exceed its $1.47 billion commitment for years 2007 to 2011 by $399 million.

Table I-2
$1.47 Billion Comparison ($million)[2]

	CY2007	CY2008	CY2009	CY2010	CY2011	Total
Actual and Budget	270	323	313	456	506	1,868
Commitment	255	272	300	325	319	1,471
Difference	15	51	13	131	189	399

As the Commission noted in its August 15 Order, The Company has implemented an asset management approach that anticipates issues based upon extensive analysis and develops strategies to mitigate issues before they occur. The investment plan reflects an expectation that the new asset management approach forecasts a significant amount of investment above historical experience. The Company believes this investment is in the best interest of customers. The Company believes the regulatory policy should support the investment levels reflected in this plan.

As explained in previous investment plan filings, the Company segregates its capital projects into five main spending categories based on the primary investment driver: (1) Statutory or Regulatory Requirements; (2) Damage/Failure; (3) Non-infrastructure; (4) Asset Condition; and (5) System Capacity and Performance.

Statutory or Regulatory work includes capital expenditures required to respond to, or comply with statutory or regulatory mandates. These include those expenditures needed to ensure compliance with the requirements of the North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC"), the Occupational Safety and Health Administration ("OSHA"), and the New York Public Service Commission. It also includes expenditures that are part of the Company's regulatory, governmental or contractual obligations, such as responding to new service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects. While in some circumstances, the company has some limited discretion on the timing of when projects go into service, such as those required to meet NERC requirements, for the most part, the scope and timing of this work is generally defined by others and is non-discretionary for the Company.

Damage/Failure category projects are those capital expenditures required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or unplanned/other deterioration, among other causes. The Company views the Damage/Failure category as a mandatory category of work that is non-discretionary in terms of scope and timing.

System Capacity and Performance projects are required to ensure that the electric network has sufficient capacity, resiliency, or operability to meet the growing and/or shifting demands of the system and our customers. Projects in this category are intended to reduce degradation of equipment service lives due to thermal stress, to improve performance of facilities where design standards have changed over the years, and to provide appropriate

[2] Expected investment spending in CY10 and CY11 are represented by FY11 and FY12, respectively.

degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies. In addition to accommodating load growth, the expenditures in this category are used to install new equipment such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with a service event. It also includes spending to improve the performance of the network such as the reconfiguration of feeders and the installation of feeder ties.

Asset Condition expenditures are those investments required to reduce the likelihood and consequences of failures of transmission and distribution assets, such as replacing system elements like overhead lines, underground cable or substation equipment. The Company has adopted an Asset Management approach that relies on a holistic, longer-view assessment of assets and asset systems to inform capital-investment decisions. As part of this approach, the Company conducts assessments of major asset classes such as circuit breakers or subsets of asset classes such as a circuit breaker manufactured by a particular manufacturer. The assessments focus on identification of specific susceptibilities for assets and asset systems and the development of potential remedies.

In addition to the spending on its electric network, the Company also invests a small portion of its investment budget in systems, tools, and general plant that are required to operate the network. The "non-infrastructure" category of investment is for those capital expenditures that do not fit into one of the foregoing categories, but which are necessary to run the electric system. Examples of spending in this category includes spending for radio systems and test equipment, spending to reduce the potential for flooding at substations and to perform capital repairs on substation buildings.

Figure I-1 and Table I-3 show a breakdown of the FY10-FY15 spending by category. As shown in Figure I-1, almost 43 percent of the planned infrastructure spending over the next five years will be required to address items that are mandatory and non-discretionary in terms of timing. This includes the repair of failed/damaged equipment to restore service to customers and spending to meet the Company's regulatory/statutory requirements.

Figure I-1
Spending by Category

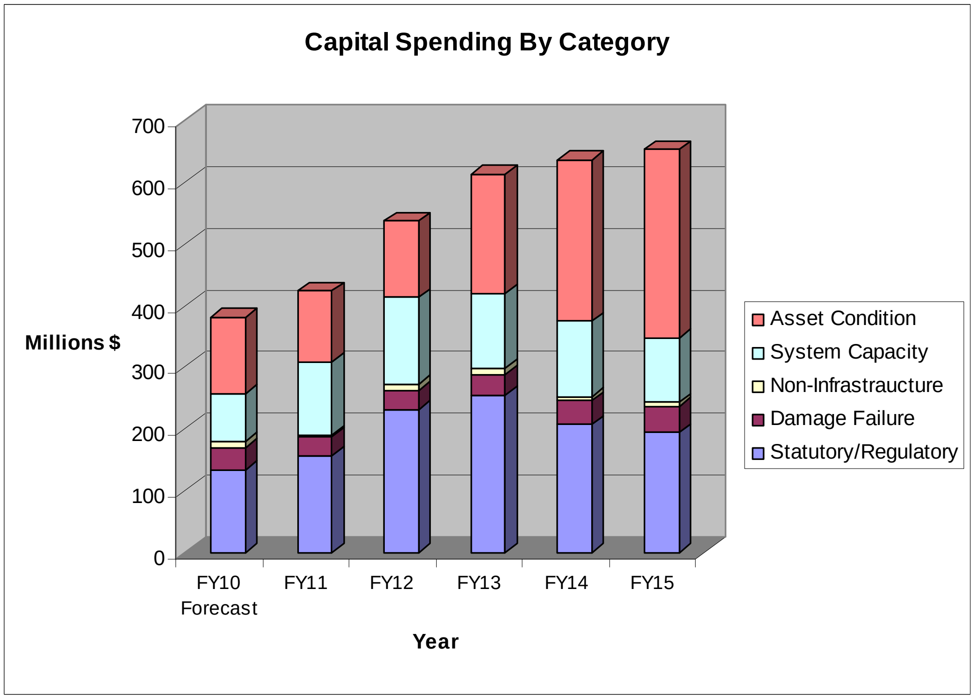

Table I-3
Expenditures by Spending Rationale ($ millions)

Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Statutory/ Regulatory	156.8	231.1	255.5	207.7	194.0	1,045.0
Damage/Failure	30.6	30.9	32.8	37.2	42.7	174.2
System Cap /Perform	119.1	139.6	121.0	122.7	104.7	607.1
Asset Condition	114.2	123.1	193.2	260.7	305.0	996.1
Non-Infrastructure	3.3	11.4	10.6	6.8	6.5	38.6
Total	**424**	**536**	**613**	**635**	**653**	**2,861**

Sections B, C and D of this Chapter summarize the Transmission, Sub-transmission and Distribution investment plans, respectively.

B. Transmission System

Chapter II describes the capital investment projects and strategies that The Company is pursuing on its transmission facilities which typically operate at voltages of 115kV and above. The Company expects to spend approximately $1.24 billion on its New York transmission system as shown in Table I-4 below.

Table I-4
Transmission System Capital Expenditure by Spending Category ($)

Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Statutory/ Regulatory	23,324,000	78,211,000	99,044,000	50,4350,000	32,248,000	283,177,000
Damage/Failure	6,101,000	5,164,000	5,915,000	9,740,000	14,200,000	41,120,000
Non-Infrastructure	100,000	6,000,000	5,000,000	1,100,000	500,000	12,700,000
System Cap /Perform	46,301,000	81,085,000	51,047,000	46,843,000	28,380,000	253,656,000
Asset Condition	56,174,000	57,540,000	128,994,000	186,967,000	219,672,000	649,347,000
Total	132,000,000	228,000,000	290,000,000	295,000,000	295,000,000	1,240,000,000

The Company intends to increase spend on its transmission assets year-on-year over the next five years from $132 million in FY10/11 to $295 million in FY14/15. Although this increase represents a significant proportion of the T&D budget forecast of $2.86 billion, the Company has reduced its forecast spend by $458 million for the period FY10/11 to FY13/14 as compared to last year's plan.

These reductions arise from the development of utility austerity programs as requested by the Commission and re-phasing of the forecast spending in order to smooth the expenditure profile in future years and recognize physical and practical deliverability constraints that are better understood based on recent projects (e.g. availability of outages, Article VII delays, etc). However, The Company is committed to maintaining, and where appropriate, improving the level of service provided to customers. Therefore, while the Company fully recognizes that many customers in New York are adversely affected by the economic downturn, the Company believes it is necessary to increase capital investment to preserve an adequate level of reliability going-forward.

The Company has provided documentary evidence as to the continuing decline in the reliability of Transmission system in upstate New York and an increasing trend in condition and performance issues for different asset populations (most recently in the Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009). The Company's investment in the past ten years has slowed this decline and, as a result, reliability performance has improved in some areas. However, without significant and sustained investment, the Company contends that this improvement will be halted and reliability performance will begin to decline.

The Company's ongoing planning process continues to identify "Strategies" that could be required to meet its customers' projected needs, as well as strategies that could improve reliability by further reducing asset failure risk. If The Company were to pursue all of those Strategies, it could invest $1.24 billion in its transmission assets over the next five years.

These strategies and their justification are described in further detail in Chapter II of this filing.

The following are some highlights of transmission system accomplishments from 2009.

- Received Article VII approval for Gardenville-Homer Hill - began construction to refurbish one of the worst performing lines in the State.
- Completed the Clay 345kV substation rebuild project.
- Initiated a program of projects to replace shield wires on multiple circuits to improve overall circuit reliability, one circuit complete and two in construction to date.
- Completed replacement of three remaining General Electric 345kV ATB circuit breakers.
- Secured a qualified contractor to refurbish the Leeds Static VAR Compensator, work to be completed in FY10/11.
- Started refurbishment on Lockport Mortimer 113/114 circuit to improve overall circuit performance.
- Submitted a new Article VII application for the refurbishment of Lockport Mortimer 111 circuit.
- Completed upgrade of 115kV circuit breakers at Packard substation to support system infrastructure improvements following closure of Huntley Power Station.
- Supported the completion of the construction of Empire Generation Transmission assets.
- Accelerated a series of projects, North East Region Reinforcement, to accommodate the connection of Global Foundries at the Luther Forest Technology Campus.
- Added or replaced three Digital fault Recorders with one in construction as part of the ongoing strategy.
- Added or replaced 25 Remote Terminal Units with 15 in engineering as part of the ongoing strategy.

C. Sub-Transmission System

Chapter III describes the capital investment Strategies and projects that are being pursued on its sub-transmission facilities. Sub-transmission facilities operate at voltage levels typically between 23kV and 69kV. These strategies address equipment concerns that cause safety and reliability issues. This process is farthest along for substation equipment and wood poles for which fully developed strategies exist and are being implemented. Other strategies in sub-transmission, such as for underground cable, towers and circuit hardening, still require further analysis for development. Projects for these strategies are included in the budget where condition, loading or reliability performance has indicated a need for specific work.

The current five year spending plan for sub-transmission is represented in Table I-5.

Table I-5
Sub-Transmission System Capital Expenditure by Spending Category ($)

Spending Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Statutory/Regulatory	11,708,000	10,846,000	11,882,000	12,411,000	11,946,000	58,793,000
Damage/Failure	3,619,000	3,767,000	3,885,000	3,985,000	4,103,000	19,359,000
System Capacity & Performance	7,641,000	8,317,000	17,199,000	16,108,000	17,139,000	66,404,000
Asset Condition	25,032,000	30,070,000	25,034,000	32,496,000	38,812,000	151,444,000
Total	48,000,000	53,000,000	58,000,000	65,000,000	72,000,000	296,000,000

This five year plan envisions significant additional expenditures on the sub-transmission system in the areas of asset condition and system capacity and performance. These additional investments were formerly captured in the "Other" spending category as these funds were not allocated to specific projects within the budget.[3] Further details are provided in the Chapter III.

The following are some accomplishments for The Company's sub-transmission system in 2009.

- Completed three miles of double circuit line refurbishment and pole replacement for Schuyler-Valley 21/24.
- Design completed and currently in construction for Rathbun – Labrador #39 Rebuild.
- Completed a mile of non-contiguous pole replacement and reconductoring for Lowville-Boonville #22 Rebuild.
- Completed all Line work for Rotterdam-Schoharie #18 Refurbishment.
- Refurbished four miles of line and replaced 120 poles for Shaleton-North Angola 856.
- Completed pole replacements for 45 two pole structures for Gloversville-Hill Street #3 Refurbishment.

D. Distribution System

Chapter IV describes the capital investment projects and strategies that The Company is pursuing on its distribution facilities. Distribution facilities typically operate at voltage levels below 23kV.

The current five year plan for distribution is represented in Table I-6.

[3] "Other" was a spending category used in the January 30, 2009 T&D Capital Investment Plan.

Table I-6
Distribution System Capital Expenditure by Spending Category ($)

Spending Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Statutory/Regulatory	121,588,000	141,754,000	144,586,000	144,765,000	150,066,000	702,759,000
Damage/Failure	20,934,000	22,104,000	22,916,000	23,717,000	24,633,000	114,304,000
System Capacity & Performance	65,090,500	50,263,000	52,784,000	59,577,000	59,103,000	286,817,500
Asset Condition	33,141,000	35,485,000	39,130,000	41,165,000	46,220,000	195,141,000
Non-Infrastructure	3,246,500	5,394,000	5,584,000	5,776,000	5,978,000	25,978,500
Total	244,000,000	255,000,000	265,000,000	275,000,000	286,000,000	1,325,000,000

Further details are provided in Chapter IV.

The following are some accomplishments for The Company's distribution system in 2009.

- Approximately 4,300 poles replaced
- Over 650 line transformer replacements
- More than 1,030 miles of feeder hardening completed;
- Approximately 190 reclosers installed
- Replaced 12,405 potted porcelain cutouts
- Buffalo Stations 23, 29, 43 and 52 rebuilds are under construction and 40 percent complete.

E. Opportunities and Risks

In developing and implementing its T&D investment plan the Company has and will continue to plan and make adjustments in order to maximize opportunities for greater efficiency while minimizing the impact of those risks that might impair the ability of the Company to meet its goals of cost effective, safe and reliable service to customers. Chapter V discusses in further detail other opportunities and risks that impact, or could impact, the Company's capital investment plan, and how the Company has responded to these opportunities and risks. Overall, although the Company faces various challenges on this front, the most acute of which are tied to the global economic downturn, the Company believes that these risks are and will continue to be manageable, and that there are also significant opportunities for improving efficiency.

Recognizing these risks and opportunities, the current economic environment facing customers, and PSC concerns the Company has reduced its planned investment. The Company believes that it remains reasonable to invest in its T&D facilities at these new levels and believes that the programs and projects described in this Plan are required to meet the needs of its customers.

F. Organization of this Filing

The remainder of this document provides detail on the programs which comprise the Five Year Capital Investment Program as well as greater detail on opportunities and risks associated with this plan. The document is segmented into the following chapters:

Chapter II – Transmission System

Chapter III – Sub-transmission System

Chapter IV – Distribution System

Chapter V – Opportunities and Risks

Chapter VI – Exhibits

II. TRANSMISSION SYSTEM

The major requirements of the transmission system are to provide customers (i.e., those both directly and indirectly connected to the transmission system) with a safe, reliable, sustainable and cost-effective transmission system.

Among the main drivers for the proposed investment are declining reliability issues, safety concerns arising from deteriorated equipment, environmental protection efforts and long-term risk management concerns stemming from asset condition and performance. Addressing these issues will ensure that The Company's transmission facilities continue to meet the minimum legal, regulatory and contractual obligations of the Company and will provide customers with a cost-effective and sustainable transmission service now and in the future.

Having identified areas needing to be addressed, the Company develops asset strategies and related programs to address each significant area. These strategies and programs consider various options (both long-term and short-term), the risks, the high level costs involved to address the non-conformance issues and the projected benefits to customers.

Table II-1 below shows the current forecast of capital expenditure for Transmission overall and by category.

Table II-1
Transmission System Capital Expenditure by Spending Category ($)

Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Statutory/ Regulatory	23,324,000	78,211,000	99,044,000	50,4350,000	32,248,000	283,177,000
Damage/Failure	6,101,000	5,164,000	5,915,000	9,740,000	14,200,000	41,120,000
Non-Infrastructure	100,000	6,000,000	5,000,000	1,100,000	500,000	12,700,000
System Cap /Perform	46,301,000	81,085,000	51,047,000	46,843,000	28,380,000	253,656,000
Asset Condition	56,174,000	57,540,000	128,994,000	186,967,000	219,672,000	649,347,000
Total	132,000,000	228,000,000	290,000,000	295,000,000	295,000,000	1,240,000,000

Details of the Five Year Capital Investment Plan at Program level are shown in Exhibit 1 and details of the individual projects within these Programs are shown in Exhibit 2.

The following table lists the major changes to the Capital Investment Plan over the past 12 months.

Table II-2
Changes since 2009

Statutory & Regulatory			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
C32539	Clay 115kV station line project	+$4.1m	C32539 is an overhead line project associated with the Clay 115kV Station Rebuild. These line work expenditures were transferred over from C28705 which should only capture station expenditures for the project. Project C32539 is expected to be completed in FY12/13.
C03256	Transmission tower clearances	+$18m	The start of the project has been rephased,. conceptual engineering is now underway. The $18m increase includes $15m added in FY14/15.
CNYX39, CNYX39A C18250, C31418, C31326 & C31419	Northeast Region Reinforcement	-$71m	Following a review of the magnitude and timing of the possible costs associated with the 345kV reinforcement identified as required to resolve the transmission performance issues in the Northeast Region a 230kV option was developed. The 230kV option resulted in significant cost savings compared to the 345kV option.
CNYPL08	New distribution for load growth	-$2m	$2m removed from FY10/11 to reflect austerity program and reduced load growth forecasts.
C28686	Porter – 115kV upgrade to bulk power	-$23m	Project re-classified to Statutory / Regulatory from System Capacity & Performance. The project has been re-estimated and re-phased following conceptual engineering. Sanctioning will occur in late calendar year 2010.
C29483	Replace 23 meters (Interconnect / NYISO)	+$5.7m	Original project scope changed from installing 23 revenue grade meters to now 51. Also testing and upgrading potential transformers at Mortimer station to revenue classification grade was determined to be required and added to the scope.

Damage / Failure			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
C26923	NY Inspection projects (capital)	-$6.2m	Estimated amount of work required in FY10/11 and FY11/12 has been reduced based on inspection results to date.
C11640	Wood pole strategy	+$4m	This project has been renamed. SG009, encompassing woodpecker damage, insect damage, rotting and ground line rejects. The prior project name was not representative of the strategy scope.

System Capacity & Performance			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
C11496	Refurbishment of Huntley 230kV station	$0	The start of the project has been delayed by 24 months. The delay is connected with changes to the Frontier region project specifically, the construction of the new Tonawanda station.
C24018	Rebuild #181 and #180 (part of SG075)	+$8.3m	This replaced the existing Line #181 Rehabilitation project, so funds from C21376 were transferred into C24018.
CNYPL28	Syracuse area re-conductoring	+$3.5m	This is a new project that was not in the 2009 CIP.
C11494 & C11495	Frontier Region	+$60.6m	Frontier Region scope increased due to the additional costs associated with the NYPA breakers, Packard increased requirements and a more thorough assessment of civil and electrical costs for the station and line work has resulted in cost increases.
C24015	Construct Southwest station	-$1.8m	Project re-phased to have Southwest station in service by spring of CY2012 due to pressing need for voltage support in the area.
C24629	Construct Southwest station	+$2.9m	Conversion of the #109 line to 115 kV as part of SG077. The cost estimates and spend profile for the project have been updated.
C24631	Golah work for #109 conversion	+$4.3m	Golah work for #109 conversion as part of SG077. The strategy (SG077, v2) was revised in May 2009 to change how the York Center substation will be supplied. Projects C15791 and C15789 were cancelled and C24631 was increased to reflect the change in work required for the new plan.
CNYAS19	Line Segmentation (Phase 1)	-$13m	At this point no work has been undertaken to identify the location and benefits of additional line segmentation therefore this prospective project has been postponed.
CNYAS86	Physical security strategy	+$9.1m	This is a new project at the request of the Office of Utility Security at the NY DPS.

Asset Condition			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
CNYAS24	Meco – replace 115kV PTs and circuit breakers	-$5m	The start of the project has been delayed by 12 months and forecasted spending re-phased. $5m has been moved into FY14/15 from FY13/14 but overall the forecast remains the same. This project has also been transferred from the Substation Rebuilds program to the Circuit Breaker Replacement program.
CNYAS07	NY Circuit breaker replacement (Priority 4)	$0.75m	The start of the prospective project has been delayed by 12 months due to resource constraints and the forecast spend has been re-phased.
CNYAS06	NY Circuit breaker replacement (Priority 3)	$2m	This prospective project has been re-phased to provide continuity with CNYAS07. An additional $2m has been added in the outer years.
CNYAS43	Queensbury – replace oil circuit breakers	-$11.25m	This project is now included under CNYAS06 & CNYAS07.
CNYAS30	Tilden – replace 115kV oil circuit breakers	-$11.25m	This project is now included under CNYAS06 & CNYAS07.

Asset Condition			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
CNYAS25	Whitehall – replace 115kV oil circuit breakers	-$1.25m	This project is now included under CNYAS06 & CNYAS07.
CNYX30	Strategy to replace flying ground switches	-$3.25	This project was approved in November 2009. The revised cost estimates reflect the conceptual engineering forecasts. Preliminary engineering is now underway on this project.
C33847	Battery replacement strategy	+$3.1m	This is a new project to continue the battery replacement work previously done under project C24239 and C32957. This recurring substation battery replacement program was approved in November 2009.
C29000	NY Polymer insulator replacement	-$11.7m	Although this work is still necessary it has been decided that an individual project is not required to achieve the objectives of the strategy. Polymer insulators will be replaced during other rehabilitation projects and the costs will be included within these projects. The previously forecast $11.7m is included in $266m overhead line refurbishment program.
CNYAS56	Indeck / Oswego – Lighthouse Hill #2	+$16m	Reclassified as part of the overhead line refurbishment program (SG080). $6m in construction spending moved up to FY14 and $10m into FY15.
C08017 (see also C07918 above)	Leeds – Pleasant Valley 91/92 tower reinforcement	+$18.85m	Correctly reclassified as part of the 3A/3B tower replacement strategy. Costs revised to more accurately reflect actual costs seen on the Edic-New Scotland 14 Type 3A-3B Tower Replacement.
C27042	New Gardenville TB 3 & TB4 replacement	-$4.67m	Scope of project has now changed to procuring and placing two new transformers at Gardenville as spares. They will be put in their permanent location and connected to the system as part of the Gardenville Station Rebuild project (C05156).
C31658 (previously CNYAS14)	NY Surge arrester replacement	-$2.71m	The start of the project has been delayed by 12 months. Forecast completion is now FY14/15. This work will now be completed as individual damage/failure projects during normal planned maintenance work on the transformers.
CNYX72	PIW Prospective projects	+$10m	This is a new budgetary reserve line item to recognize that issues found during inspection or maintenance often needs capital expenditure to resolve. PIWs (problem identification worksheets) are generated from the field to identify these issues which are then prioritized and engineering solutions are proposed.
C03389	Gardenville – Dunkirk 141 / 142 T1620 – T1270 ACR	+$30.45m	Project now incorporates re-conductoring with 796 kcm instead of 477 kcm conductor. Delay more accurately reflects anticipated Article VII process.
C05161 & C05162	Wood arm replacement & Replace laminated wood davit arms	-$35m	These two prospective projects were previously included to manage predicted wood cross-arm issues that had been observed in areas. After further assessment, differences in design have been identified and this work is no longer forecasted. Any future cross-arm issues will be addressed through the Overhead Line Refurbishment strategy.

Asset Condition			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
C27425 C04718	Gardenville – Homer Hill 151 / 152 ACR	-$23m -$10.2m	C27425 is for the southern portion of the line which is still in conceptual engineering. C04718 is for the northern portion and is currently under way.
C27432	Lockport 103 / 104 STR	+$8m	$8m added to FY14/15 reflecting forecast start of construction activity.
C03417	Lockport – Mortimer 111 ACR	+$16.3m	Construction activity in FY10/11 reduced based on Article VII requirement. Remaining construction activity condensed into three years. Costs increased to reflect scope of work and preliminary engineering costs.
C30889	Pannell – Geneva 4 / 4A	+$14m	$14m added to FY13/14 to reflect start of construction activity.
C30890	Porter – Rotterdam #31	-$4m	The start of the project has been delayed by 12 months.
CNYAS82	Ticonderoga lines 2 & 3 rebuild	-$10m	Project re-phased with the majority of the construction activity now forecast to occur in FY14/15. Overall the cost forecast remains the same.
CNYAS10 (previously CNYX45)	Protection replacement (Phase 1)	-$2m	Project re-phased to smooth replacement profile.
C17849	Rotterdam replace 230kV RHE CBs	+$65.7m	Following site condition assessment, the scope of this project has expanded significantly to address all of the asset condition issues at this critical 230kV site. The current scope involves the construction of a new 230kV site on a flat piece of adjacent land. Other possible options at this development stage are a new 230kV GIS station or a 345kV option. Conceptual engineering is currently ongoing but overall costs are likely to >$100m over the total project.
C05156	Gardenville rebuild	+$20m	Conceptual engineering has been performed for this project and better cost estimates have been prepared along with a more realistic forecasted spending profile. The total estimated cost of this project is now estimated to be $100m.
C03778	Rome 115kV station rebuild	-$9m	Conceptual engineering has been undertaken for Rome and the Strategy was approved in November 2009. The revised forecast reflects the more accurate scope of work and likely timing.
C31656 (previously CNYAS03)	NY Replace priority 4 transformers	-$20.8m	The project has been re-phased to reflect physical constraints regarding the number of transformer outages that could be scheduled/planned in any given outage year.
CNYAS04	NY Replace priority 3 transformers	-$19.8m	The start of the project has been delayed beyond FY15. This prospective program will be a continuation of C31656.
C27422	Falconer-Homer Hill 153-154	-$14m	This project was placed on hold due to potential outage conflicts with other Western NY projects. It is now scheduled to be re-evaluated in FY11/12.
C21694	Spier-West refurbishment	-$6m	Project deferred following engineering to the point of sanction. $7.9m for refurbishment costs need to be added after FY15.
C21376 (see also C24018)	Packard Urban 181 refurbishment	-$8.6m	Project cancelled due to Frontier Program

Asset Condition			
Project Number	**Project Title**	**2010 CIP vs. 2009 CIP**	**Explanation of difference**
C05155	Dunkirk rebuild	-$20m	Began conceptual engineering to identify work scope. Forecasted cost excess of original $27m pre-conceptual estimate but with spend to FY15.
CNYAS1	New Scotland Rebuild	-$32.6m	Initially it was anticipated that New Scotland would become a Bulk Power System classified site. This is no longer the case and this project is no longer required.
CNYAS11 & CNYAS12	Bay infrastructure replacement	-$13.3m	This prospective project was to replace disconnects, PTs, cable, etc at sites where circuit breaker replacement was proposed. These costs are now included in CNYAS06 and CNYAS07.
C24012	Gardenville Cap Banks	-$5.2m	The installation of capacitor banks is not required with the rebuild of Gardenville substation (C05156).
C30229	Rotterdam New 230 to 115kV Transformer	-$7m	The funds for this project were moved into the Rottredam 230kV yard rebuild project.
C27006	Packard – Replace Transformer Banks 3 and 4	-$5.3m	Costs reduced to reflect latest estimates.
C29844	Colton Replace CBs and disconnects	-$1.3m	This project has just started and is in pre-sanction phase with a April 2010 sanction anticipated.
C31663 (previously CNYAS45)	Greenbush- Replace TB3	$1.6m	Delayed one year to further assess condition.

The following are some highlights of transmission system accomplishments from 2009.

- Received Article VII for Gardenville Homer Hill, started construction to refurbish one of the worst performing lines in the State.
- Completed the Clay 345kV substation project.
- Initiated a program of projects to replace shield wires on multiple circuits to improve overall circuit reliability, 1 circuit complete and 2 more are under construction.
- Completed replacement of 3 remaining General Electric 345kV ATB circuit breakers.
- Secured a qualified contractor to refurbish the Leeds Static VAR Compensator.
- Started refurbishment on Lockport Mortimer 113/114 circuit to improve overall circuit performance.
- Submitted a new Article VII application for the refurbishment of Lockport Mortimer 111 circuit.
- Completed upgrade of 115kV circuit breakers at Packard substation to support system infrastructure improvements following closure of Huntley Power Station.
- Supported the completion of the construction of Empire Generation Transmission assets.
- Accelerated a series of projects, North East Region Reinforcement, to accommodate the connection of Global Foundries at the Luther Forest Technology Campus.
- Added or replaced 3 Digital fault Recorders with 1 in construction as part of the ongoing strategy.
- Added or replaced 25 Remote Terminal Units with 15 in engineering as part of the ongoing strategy.

The remainder of the chapter will briefly describe the major capital investment programs. Specific asset condition and performance issues are described in further detail in the annual Condition Filing to the PSC, most recently filed on October 1, 2009. Each section describes the drivers for capital investment programs and the projected customer benefits along with a description of any changes between the January 2009 Capital Investment Plan and this filing.

A. Statutory/Regulatory Strategies and Programs

Capital spend in this category are required to ensure that the facilities meet the minimum legal, regulatory and contractual obligations of the Company. These include those expenditures needed to ensure compliance with the requirements of the North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC"), and the Occupational Safety and Health Administration ("OSHA"). For the most part, the scope and timing of this work is dictated by others and is non-discretionary for the Company.

Northeast Region Reinforcement

This major program consists of reinforcements of the transmission system in the Saratoga and Glens Falls area and is necessary to respond to reliability needs caused by area load growth and the impact of the proposed Luther Forest Technology Campus ("LFTC"). The transmission reinforcement program will resolve thermal and voltage problems which will result from projected load growth in the Northeast Region. Currently, there are six major projects with forecasted spending levels over $2 million under this program including the construction of the new Turner Road station and the associated taps, the re-conductoring of 44 miles of right-of-way miles of 115kV lines and the installation of a fourth transformer at Rotterdam.

The plan is made up of the following key elements:

- Install a new 230/115kV substation where the existing Rotterdam-Bear Swamp 230kV line crosses the existing Mohican-North Troy #3 line and the Battenkill-North Troy #10 115kV lines. This station would serve as a primary source to those lines serving the east side of the 115kV northeast system.
- Install a new 115kV line parallel to the existing Spier Falls to Rotterdam #1 & 2 circuits. This line would reinforce the west side of the 115kV system that serves the northeast.
- Re-conductor 44 miles of existing 115kV lines that provide power to the northeast region.
- Install a fourth 230/115kV Transformer at Rotterdam Substation.

Drivers:

The transmission system which serves the Northeast Region is currently exposed to post-contingency thermal overloads during summer peak periods. These violations of The Company's Transmission Planning Guide (TGP28) show inadequate thermal capacity with respect to the three Rotterdam 230/115 kV transformers and the Spier-Rotterdam #1/#2 115 kV double circuit. This shows a need to simultaneously add bulk-power transformation capacity and relieve 115 kV thermal overloads which affect the transmission supply to the Northeast Region.

The Company has worked with Luther Forest Technology Campus Economic Development Corporation (LFTCEDC)[4] toward developing LFTC. As discussed in the 2009 Asset Condition Report, with Global Foundry's (GF) commitment to build a chip-manufacturing plant at the site the projected load growth within the Northeast Region will exacerbate transmission system performance issues.[5]

Additionally, the Saratoga/Glens Falls area has been experiencing significant load growth. Its annual projected growth rate is three percent annually projected over the next 10 years. If the LFTC develops as expected, the anticipated direct and ancillary jobs it would create could cause the growth rate to increase to an annually projected rate of seven percent over the next 10 years. Further details are provided in Exhibit 3.

Customer Benefits:

The transmission reinforcement plan will resolve thermal and voltage problems resulting from projected load growth in the Northeast Region. More specifically, the 230/115 kV transformers at Rotterdam and Spier-Rotterdam #1/#2, which are primary components of the transmission supply for the Northeast region already exceed their ratings for certain contingency conditions according to The Company's Transmission Planning criteria. This will worsen over time, since the LFTC is connected to the transmission system and the load is projected to grow. Without improvements being made to the transmission facilities in this area, the development of the LFTC could be jeopardized.

Additionally, the transmission reinforcements program will reduce dependence on local generation for reliability of service within the region.

2009 and 2010 Variance Explanation:

The primary variance between the current plan and the 2009 Capital Investment Plan (CIP) is that the 2009 CIP was based upon a 345kV reinforcement to serve the east side of the Northeast Region. It included two new substations at the South Saratoga and Princetown sites. While the current plan reinforces the existing 230kV and 115kV systems, with reinforcements being made to both the east and west sides of the existing system.

Additionally, the Luther Forest relay/high speed communication work has been removed from this project. The work is not part of the Northeast Regional Reinforcement Plan; it is necessary to support the high speed clearing requirements of the GF manufacturing facility at the LFTC and therefore included in that project.

[4] Formerly known as the Saratoga Economic Development Corporation (SEDC).

[5] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pgs. II-17 to II-18.

Table II-3
Program Variance ($)[6]

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	6,287,000	17,037,000	78,616,000	127,219,000	12,470,000	-	235,342,000
2010 CIP	-	7,342,000	41,160,000	64,993,925	38,450,000	18,898,243	170,844,168

Station Bulk Power System Upgrades

This major asset program relates to the need (following network analysis) to upgrade two of our 115kV substations to bulk power reliability criteria, the Clay 115kV and Porter 115kV substations.[7] The status of these two stations has been confirmed by the New York ISO to be Bulk Power System facilities (BPS); therefore, investments are required for them to comply with the more stringent NERC and NPCC requirements for such facilities which have the potential to affect the regional grid.[8]

Drivers:

In April 2007, NPCC adopted Document A-10, Classification of Bulk Power System Elements. In accordance with Document A-10, testing of the major substations across New York State was performed by the NYISO, and several The Company substations were classified as part of the bulk power system (BPS). All substations that were newly classified as BPS under the A-10 testing must be brought into compliance with specific NPCC design, protection and operation requirements.

Further discussion of program drivers can be found in Exhibit 4.

Customer Benefits:

In addition to compliance with NPCC and NYSRC requirements, the benefits of completing these projects are reductions in system vulnerability to certain severe contingencies. These projects reduce the likelihood that system instability and voltage collapse will occur for these contingencies:

- If a three-phase fault on the 115kV bus at Clay 115kV station fails to clear locally, studies show that generation at the Oswego complex and the local area will go out of synchronism causing widespread system collapse in central and western New York. This risk is mitigated by upgrading the Clay 115kV station to NPCC bulk power system requirements.

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[6] Totals in all Program Variance tables in the document are for the five year FY10/11 to FY14/15. FY09/10 is provided for reference.

[7] In the September 17, 2007 Transmission and Distribution Capital Investment filing, this program referred also to the New Scotland 115kV substation as a candidate for upgrade. The NYISO has determined New Scotland was not a bulk power facility and thus has been dropped from this program.

[8] This program was discussed in more detail in Appendix 1, Attachment 4 of the April 21, 2009 Petition to Defer Electric Transmission & Distribution Investment Costs (Case 07-E-1533).

- A three-phase fault on one 115kV bus at Porter would cause loss of both 115kV buses should the bus tie breaker fail to clear. The result would be voltage collapse and loss of load throughout a large area of central New York. In addition, many of the breakers are exposed to possible fault currents in excess of their interrupting capability, creating a risk of failure to clear a fault and the safety hazards associated with breaker failure. These risks are mitigated by upgrading the Porter 115kV station to NPCC bulk power system requirements and the addition of a second bus tie breaker.

Customers in central New York will benefit from reduced vulnerability of the transmission system to these highly disruptive contingencies.

2009 and 2010 Variance Explanation:

The project has been re-phased and broken out into 115 and 230 kV portions for work at Porter. Three development project funding numbers have been set up for 230 kV work at Porter - CNYAS33, CNYAS34 and CNYAS36. Currently only CNYAS36 has funding included in it ($11.25m) and is listed within the Station Rebuild program of the 2010 CIP.

Table II-4
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	7,500,000	37,000,000	28,775,000	3,498,655	0	-	69,273,655
2010 CIP	-	9,850,000	20,000,000	23,000,000	-	-	52,850,000

Conductor Clearance Strategy

The conductor clearance correction program will increase the clearance of certain overhead conductors.[9,10] The need for greater clearances was identified as a result of a 2005 review of the transmission system using an innovative technology called Aerial Laser Survey (ALS). Clearances were measured with aerial surveys providing an accuracy which was previously available by ground inspection only. The facilities at issue are the Company's overhead transmission lines that may not meet clearance standards prescribed by the National Electric Safety Code (NESC) under certain ambient loading conditions.

The code requirements vary depending on what date the transmission line went into service. Clearance projects will be prioritized based on the enhancement of public safety, but at the same time the work will be bundled by geographic areas to ensure efficient delivery. In order to enhance public safety, the Company will bring clearances over railroads, roads, streets, driveways, parking lots, water bodies and clearly developed right-of-way access roads crossing under a span up to current standards even in cases where existing clearances

[9] The Clearance Strategy (SG029v2c) was included as Exhibit 18 in Volume 4 of 9 in the September 17, 2007 Compliance Filing, Case 06-M-0878.
[10] The Conductor Clearance Strategy was further discussed in the Report on the Condition of Physical Element of Transmission and Distribution Systems, October 1, 2009, Table III-26, pg. III-31/32

are grandfathered. When actual modifications are needed, the cost to upgrade from the governing code to the current code is relatively minor (a span is seldom substandard to the current code but not the governing code over these types of crossings). Designing to the conductor clearances to current code over these higher exposure locations provides additional safety enhancement to the public for a relatively low cost. There is one major project within this program - the Transmission Tower Clearance project.

Drivers:

This program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built by improving ground to conductor clearances in substandard spans. This follows standard industry practice and Public Service Commission Order (per Case 04-M-0159 effective January 5, 2005) that The Company adhere to the NESC.

The primary driver for this work is to ensure the safety of the New York public and our staff as they work and travel under the overhead lines. Without this work, there remains an elevated risk of significant safety incidents associated with overhead line clearances. The NESC sets obligatory conductor clearances of overhead lines from the ground and other ground based objects. For further discussion on the drivers for this program refer to Exhibit 5.

Customer Benefits:

While safety events caused by substandard clearance conductors are rare, their consequences are extremely serious. Since it is possible to minimize the risk from undesired conductor contact through adherence to the NESC, it is necessary that the network is assessed, and steps are taken to ensure that the transmission assets meet this standard.

2009 and 2010 Variance Explanation:

The variance is chiefly due to the spending already incurred in FY2009/10 and conceptual level re-phasing of the strategy and the additional spend in FY14/15.

Table II-5
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,850,000	2,000,000	10,000,000	15,000,000	15,000,000	-	42,000,000
2010 CIP	-	1,499,000	15,000,000	15,000,000	15,000,000	15,000,000	61,499,000

Remote Terminal Units Strategy

The Remote Terminal Unit ("RTU") Strategy involves replacing obsolete monitoring and control equipment with current and fully functional equipment.[11] There are currently approximately 550 operating RTUs under The Company's control in New York, of which 123 would be replaced under this program.

Obsolete RTUs will not work with the modern energy management systems the Company expects to implement by 2011. NERC Recommendation 28, released in response to the August 2003 blackout, requires the use of, among other things, more modern, time-synchronized data recorders. Many in-service RTUs do not satisfy this requirement.

Drivers:

The RTUs are being replaced under this major program for the following reasons:

- These RTUs and equipment are obsolete and in most cases no longer supported by the manufacturer. Replacement parts are either difficult to obtain or unavailable.[12] Failure of the RTU may be un-repairable, requiring a complete unplanned replacement at short notice. This situation could occur when data from the failing RTU is most critical, such as during system events, resulting in a negative reliability impact.
- Test equipment is obsolete and cannot be readily obtained or maintained. The PC based test equipment required for maintenance was acquired in the early 1990s and uses a DOS software platform. Both the RTUs and test sets utilize the M9000s communication protocol. This protocol is the legacy protocol of the original EMS and cannot be upgraded.
- These RTUs are not suitable for future integration of new substation devices and technology. The equipment does not have and cannot be modified to provide the capabilities required for modern supervisory control and data acquisition.[13] This type of functionality is becoming standard to meet current reliability needs.
- These RTUs are not compatible with the planned EMS system replacement.
- These RTUs do not meet the criteria outlined in NERC Recommendation 28, which was issued in April, 2004. This places the company at risk for not being able to provide synchronized system data during a system emergency.[14]

Refer to Exhibit 6 for more discussion on the drivers.

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[11] The Remote Terminal Unit Strategy (SG 002) was included as Exhibit 20 in Volume 5 of 9 of the September 17, 2007 Transmission and Distribution Capital Investment Plan, Case 06-M-0878.
[12] SG002 – Revised Asset Replacement Strategy for RTUs, October 31, 2005 (Capital Investment Plan, Exhibit 20.A)
[13] SG002 – Revised Asset Replacement Strategy for RTUs, October 31, 2005 (Capital Investment Plan, Exhibit 20.A)
[14] North American Electric Reliability Council (NERC) "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April 5, 2004 Page-162

Customer Benefits:

The new RTUs will provide quicker and more reliable data than their predecessors. In the event of a minor or major system disturbance, accurate data that is received in a timely manner is a necessity in the restoration process. Data received from the new RTUs will quickly identify key devices that have failed or have been affected by the event. The data will expedite isolation of the problem, reduce the duration of the outage and in some cases avoid expansion of the outage to other system components.

Furthermore, if obsolete RTUs are not replaced, they will not be able to communicate with the new Energy Management System which would then prevent the required modern supervisory control and data acquisition of the Transmission system from taking place. This type of functionality is required to meet current reliability needs.

2009 and 2010 Variance Explanation:

The RTU replacements have been delayed due to both the difficulty in outage scheduling and the length of time necessary to install the digital communication circuitry needed for the new RTUs.

Table II-6
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,800,000	1,900,000	700,000	700,000	-	-	3,300,000
2010 CIP	-	1,455,000	2,000,000	1,400,000	-	-	4,855,000

B. Damage/Failure Strategies and Programs

Damage/Failure category projects are those capital expenditures required to replace failed or damaged equipment and to restore the system to its original configuration and capability as a result of damage or equipment failure on an as-needed basis. Damage may be caused by storms, vehicle accidents, vandalism, deterioration, or other causes. The Company views Damage/Failure as mandatory.

New York Inspection Projects

Replace damaged and failed transmission overhead line components identified during field inspections (five year foot patrols, annual infrared inspections, etc.).

Driver(s):

This program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built by replacing hardware, wood poles, and structure components that no longer meet the governing code requirements. This follows standard industry practice and the Public Service Commission Order per Case 04-M-0159 effective January 5, 2005 to adhere to the NESC.

For the majority of situations, components no longer meet the NESC code and may even pose an imminent safety hazard. Further details can be found in Exhibit 7.

Customer Benefit(s) of Program:

Maintenance of appropriate public safety level by assuring that damaged or failed Transmission components are replaced and continue to meet the governing National Electric Safety Code under which they were built.

2009 and 2010 Variance Explanation:

Funding project, C26923, is in place to address damaged or failed components when identified through the five year Computapole inspection process. These inspections will continue to result in new capital and operational related expenditures as the damage/failure components are discovered in the field.

Spending levels during the last two years have been lower than originally projected due to implementation and initial engineering lead times. The 2010 Capital Investment Plan adjusts the spending to account for the actual spending levels. As the program becomes more comprehensively implemented costs are expected to increase.

Table II-7
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,800,000	2,800,000	3,000,000	3,000,000	3,000,000	3,000,000	14,800,000
2010 CIP	-	400,000	1,000,000	1,000,000	3,000,000	3,000,000	8,400,000

Wood Pole Management

This program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built by replacing wood poles and wooden structures that no longer meet the governing code requirements. There is one stand alone project within this program.

Drivers:

As discussed in the 2009 Asset Condition Report, wood poles that are either priority rejects or reject poles (as classified following a ground line inspection performed on behalf of the Company by Osmose Utilities Services Inc, of Buffalo, NY) as well as the ones damaged by woodpecker or insect activity will be replaced. This follows standard industry practice and the Public Service Commission Order per Case 04-M-0159 effective January 5, 2005 to adhere to the NESC.

The wood poles targeted through this initiative are the ones that are deemed to be beyond restoration by either re-treatment or placement of some form of additional pole support, usually at the ground line.[15] Similarly, "reject equivalent" refers to deteriorated wood poles from such things as wood pecker damage, insect damage, or rotting.

For the majority of situations, reject and priority reject poles do not meet the NESC code. In a limited number of cases when an extra margin of safety was added into the design, some of this margin may still be available before failing to meet the code. However, this usually provides a limited amount of extra time to replace the damaged or deteriorated wood pole(s) or structures. Rarely could the pole, or structure, remain in place for a significant amount of time.

Further discussion on the program drivers is included in Exhibit 8.

Customer Benefits:

Customers will benefit from the maintenance of the appropriate public safety level by assuring that Transmission wood structures continue to meet the governing National Electric Safety Code. In addition to the public safety benefit, unwanted failures of wood poles or structures can lead to unreliability.

2009 and 2010 Variance Explanation:

Spending levels in the last two years have been lower than originally projected. This has been due to a longer strategy start-up and implementation timeframe than originally expected. The 2010 Capital Investment Plan adjusts the spending to account for the actual spending levels. Full field construction is targeted for mid-FY2013/14 and after. However, investment may change if the start-up and implementation schedule can be accelerated.

Table II-8
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	3,950,000	3,950,000	6,150,000	6,150,000	6,150,000	-	22,400,000
2010 CIP	-	1,750,000	1,500,000	1,600,000	3,000,000	7,900,000	15,750,000

C. System Capacity and Performance Strategies and Programs

Capital spend in this category refers to those expenditures undertaken to upgrade the capability of the system beyond minimum requirements in order to provide improved thermal loading, voltage, stability, reliability or availability performance. Such expenditures may often be aimed at addressing local system risk and performance issues. Examples might include investments to address local load relief or reliability issues.

[15] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pgs. III-17 to III-20.

Frontier Region

The Frontier Region Program involves significant capital expenditures to construct a major set of upgrades and replacements to the 115kV system near the existing Huntley Station in Western New York.[16] Load pocket studies have indicated that the Huntley area could be subjected to thermal and voltage problems if generation at Huntley and the several facilities near Huntley were retired. Upon the announcement of the retirement of the units at Huntley, further analysis of the area confirmed that thermal and voltage problems would be present and those problems would be more severe than had been initially indicated in prior load pocket studies.

To remediate the potential problems with the June 2007 retirement of the last Huntley 115kV generating unit, the region required immediate capacitive support to maintain a minimum level of service. Accordingly, The Company installed two 52.5 MVAR portable capacitor banks on the 115kV bus at Huntley Station before the generation closed in June 2007. This temporary solution following the generation retirement requires further transmission support to provide thermal and voltage security to the region.

The Company plans to construct or install new facilities that will prevent thermal and voltage problems in the area load pocket formerly supported by the Huntley generation, as well as benefiting the existing customer base through overall reliability improvement. In addition, the approach will reduce the environmental risk of a release of oil from the oil-filled equipment at Huntley, which borders the Niagara River and a small boat marina. This program is being implemented in order to ensure that appropriate thermal support and further voltage support is in place by the summer of 2012. Currently, there are two projects directly included in this program - the construction of the Tonawanda station and the relocation of the six circuits that will in future terminate at the new station. In addition to the Tonawanda projects, the refurbishment of the Huntley 230kV Station is associated with this program as well.

Drivers:

When The Company was first notified of the planned 115kV generation shutdown by NRG in January 2005, the Company commenced the planning process to mitigate the effects of the loss of this crucial generation source. Studies of the area confirmed thermal and voltage problems were present and corroborate years of actual operating experience, which demonstrated how critical these units were to support the area's voltage and thermal performance.

The Huntley area is supplied by three pairs of circuits: two from Packard, two from Lockport and two from Gardenville. The largest impact on the area occurs for multiple

[16] This program includes projects not associated with reinforcements required in the Frontier region that are included in the Reliability Criteria Compliance program described below. Strategy SG 042 for the Frontier Region was included as Exhibit 13 in Volume 4 of 9 of the September 17, 2007 Transmission and Distribution Capital Investment Plan. Further justification information was provided in the December 21, 2007 Petition to Defer Electric Transmission & Distribution Investment Costs (Case 01-M-0075) in Exhibit P-3.

element outages, such as bus faults or faults with stuck breakers at Packard, Lockport or Gardenville, as well as double circuit tower outages of any of the circuit pairs. As these contingencies affect multiple sources in the area, the loading on the remaining sources can surpass the emergency capability of the equipment. For example, the loss of the two Packard-Huntley circuits results in overloads on the Lockport-Huntley circuits.

Outages of multiple elements also have a severe impact on the voltages at Huntley and at the customer stations supplied from radial lines #46 and #47. Some outages were so severe that the voltage was falling to 80 percent of nominal, which is 10 percent below criteria and over a 15 percent drop from the pre-contingency value.

Given present system conditions and minor load growth expectations, thermal support and further voltage support is needed before the summer of 2012 in order to prevent undesirable system conditions. This date is a delay from the originally requested date of 2010. It is attributed to reduced electric demand in the area surrounding Huntley Station. Prior to 2012, the capacitor banks installed at Huntley will mitigate most post-contingency system concerns. However, should a severe fault occur during a heavy load period, load shedding would likely be required to maintain the security of the transmission system.

To meet the reliability need, the plan calls for construction of a 115kV breaker and half station to be known as Tonawanda Station (formally referred to as Paradise Station), which will replace the existing Huntley 115kV Station. This new station will include several 115kV circuits not currently terminated at Huntley as well as capacitive support. The new station will be a Gas Insulated Station (GIS). The decision to build a GIS was driven by property constraints and careful comparison of Air Insulated and Gas Insulated station costs.

The final component of this program is construction of a new control building to house the 230kV protection and control equipment at Huntley. This component of the program is driven by the desire to physically separate The Company and NRG assets and concerns with the condition and location of assets within the NRG facility. If NRG were to pursue demolition work at its facility, The Company assets would need to be removed.

Further discussion on the drivers for this program can be found in Exhibit 9.

Customer Benefit:

The planned approach is designed to prevent thermal and voltage problems that will negatively affect system security and reliability in the customer load pocket formerly supported by the Huntley generation. Without reinforcing the system, if a contingency were to occur, load shedding would be required to maintain the system performance at an acceptable level. The reinforcement will support the existing loads for all outage conditions and allow for modest load growth in the near term. However, additional projects in Western NY are required to address other thermal and voltage concerns outside the Huntley pocket.

Transmission system reliability improvements will develop through the implementation of the permanent solutions. Six circuits currently terminated at Huntley will be approximately six miles shorter once terminated at Tonawanda. These six lines are Packard-Huntley #129, Walck Road-Huntley #133, Lockport-Huntley #36 and #37, and Huntley-

Gardenville #38 and #39. The Huntley-Lockport #37 circuit is sixteenth on the 2009 Annual Worst Circuit List (third quarter update). Line #39 is eighty-fifth on the list.

Three circuits not terminated at Huntley will be split in half resulting in six circuits terminating at Tonawanda. These three circuits are Niagara-Gardenville #180, Packard-Erie #181 and Packard-Gardenville #182. The #180 and #182 circuits are twenty-ninth and forty-third respectively on the Worst Circuit List. The reduced length of these circuits will decrease their exposure, which is expected to result in a reliability improvement.

The breaker and a half station, state of the art relaying and control systems and the elimination of a third party in the operation, maintenance and control of the station will also result in an improvement of the transmission system reliability.

In addition to the reliability improvements, the retirement of equipment at Huntley and replacement of equipment at Packard Station will eliminate many oil-filled devices from the system, thereby reducing environmental hazards. This will reduce the risk of a costly environmental event.

2009 and 2010 Variance Explanation:

The projects within this program are still in the +/- 25% accuracy range and a definitive work scope is being developed. The primary driver for the difference between the 2009 CIP and 2010 CIP is due to the line and station work associated with the Tonawanda Station (formerly referred to as the Paradise Station). Estimates have been updated for ground grid, structures, foundations, site work, environmental work, temporary utilities and work necessary on NYPA breakers.

Table II-9
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	36,262,274	5,422,629	8,811,717	350,586	-	-	14,584,932
2010 CIP	-	29,250,000	54,347,000	12,301,000	5,656,000	5,150,000	106,704,000

Reliability Criteria Compliance

This program involves significant capital expenditure over the next five years to construct major reinforcements of the 115kV and 230kV transmission systems in western New York, including the Frontier, Southwest and Genesee regions that extend from the New York/Canada border east to Mortimer Station and south to the Pennsylvania border. This strategy will ensure adherence to reliability standards by strengthening the transmission network and making it fully compliant with NERC TPL Standards, NPCC Document A-2, NYSRC Reliability Rules and the The Company Transmission Planning Guide (TGP 28). It will also correct many existing asset condition, safety, and environmental concerns resulting in improved reliability of several circuits.[17]

The Company's program to remediate these potential reliability problems comprises the following components:

- Rebuilding 27 miles of double circuit 115kV transmission line between Packard, Paradise and Gardenville to correct overloads;
- Constructing a new 345/115kV station near Homer Hill station tying into the Homer City-Stolle 345kV line #37 and the Gardenville-Homer Hill 115kV lines #151 and #152 to support area voltage;
- Re-conductoring 6 miles of the Falconer-Warren 115kV #171 circuit to prevent the circuit from being opened by FirstEnergy due to their loading concerns;
- Installing a 15 MVAR capacitor bank at Andover to boost area voltage; and
- Converting a 10.5 mile 69kV circuit between Mortimer and Golah stations to 115kV to prevent low voltage conditions.

The portions of the system described above do not meet reliability standards and therefore must be upgraded. As a result, voltage support and correction of thermal overloads is needed as soon as possible.

Drivers:

Studies of the 115kV and 230kV transmission systems were conducted for the Frontier, Southwest and Genesee regions of Western New York, which extend from the New York/Canada border east to Mortimer Station and South to the Pennsylvania border. These studies were put in place in order to determine whether the systems comply with reliability standards. Studies which were performed in 2007 and then reconfirmed in 2008 evaluated the system for existing load levels up to a 10 year forecasted load level.

Included within both of these evaluations was testing of both N-1 and N-1-1 design criteria, ensuring compliance with NERC TPL Standards, NPCC Document A-2, NYSRC Reliability Rules and the The Company Transmission Planning Guide (TGP 28). These standards require the entire transmission system to meet N-0 and N-1 voltage, thermal and stability criteria as well as the bulk power system and long lead time items to meet the same criteria for N-1-1 conditions.

Several reliability criteria violations for the area were discovered under study conditions. Violations included thermal overloads on 115kV circuits in the Frontier region (N-1), 230kV and 115kV voltage problems at Gardenville (N-0, N-1 and N-1-1), thermal overloads on transformers at Gardenville (N-1-1), voltage problems around Homer Hill and Dunkirk (N-0, N-1, N-1-1), and voltage problems around Batavia, Brockport and Golah (N-1).

[17] Strategy SG 075 to reinforce the transmission system in Western NY was included as Exhibit 15 in Volume 4 of 9 of the September 17, 2007 Transmission and Distribution Capital Investment Plan.

For the Frontier region, system reinforcements are driven by the need to correct thermal overloads on the circuits between Packard, Tonawanda and Gardenville. These overloads are worse when the outages are combined with an outage of one of the 230kV circuits between Niagara and Gardenville as required by N-1-1 criteria.

The voltage at Gardenville is also outside of criteria for the system with all lines in service and for N-1 and N-1-1 conditions. The worst voltage problem is created by outages of 230kV lines or N-1-1 outages of multiple 230kV lines. The capacitor banks to be installed at Gardenville as part of the station refurbishment project will correct many voltage concerns but do not address all N-1-1 conditions.

In the Southwest region, multiple reinforcements are required to correct all N-1 conditions. In addition to the problems in the Homer Hill area, bus faults at Dunkirk will create low voltage problems on the circuits between Dunkirk and Falconer. For the Genesee region, several voltage related problems were found in the Batavia and Golah areas. For bus faults at Lockport, voltage problems develop in the Batavia area. Thermal concerns were also present on one of the circuits between Lockport and Batavia. At Golah, an outage of the circuit between Mortimer and Golah would result in Golah being fed radially from Batavia. This in turn would cause low voltage levels at Golah (below 80 percent). This contingency can also be caused by bus faults at Mortimer and Golah.

For further discussion on program drivers refer to Exhibit 10.

Customer Benefits:

Customers will benefit from this program in several ways, including:

- Exposure to service interruptions (some resulting from load shedding) in the event that certain key contingencies which may occur would be reduced significantly.
- Generation that currently must be run at times to ensure voltage support and stability will no longer be required, avoiding future costs of dispatching the generation out of NYISO merit order.
- Circuits that are normally open that provide a backup source to loads in the Homer Hill area will be operated normally closed, reducing the frequency and length of outages for certain contingencies.
- Some capability to accommodate new or expanding load will be added to the system.

Further explanation of these benefits is found in Exhibit 10.

2009 and 2010 Variance Explanation:

The 2009 CIP total amount included capital spending for the Clay and Porter 115kV Bulk Power System Upgrades within the Statutory/Regulatory spending rationale category. The Reliability Criteria Compliance program for the 2010 CIP has now been reclassified into the System Capacity and Performance spending rationale and excludes the Clay and Porter Bulk Power System Upgrade projects.

Table II-10
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	16,707,736	60,488,954	56,286,375	41,140,199	1,738,072	-	159,653,600
2010 CIP	-	11,566,000	29,799,000	33,278,000	23,091,000	18,000,000	115,734,000

Other System Capacity & Performance

There are currently eleven separate projects with spend greater than $2,000,000 included in the Other System Capacity and Performance program. One notable addition is the Syracuse area re-conductoring program.

Syracuse Area Re-Conductoring

This new program reinforces the transmission system in and around the Syracuse area. These reinforcements are necessary to respond to a system capacity and performance need caused by load growth in the area over the period of time between 2008 and 2018. Without this program, the 115kV system will be exposed to thermal overloads during contingency conditions.

The program scope includes the following projects:

- Re-conductor 6.36 miles of the Yahnundasis–Porter 115kV circuit #3.
- Re-conductor two separate sections of the Clay–Teall 115kV circuit #10. The sections targeted for re-conductoring are 6.75 miles, and 6.08 miles.
- Re-conductor 10.24 miles of Clay–Dewitt 115kV circuit #3.

Drivers:

Studies of the 115kV and 230kV transmission systems were conducted for the Central and Mohawk Valley regions of Central NY, which extend from Elbridge substation in the West to Inghams substation in the East, determining whether the systems comply with reliability standards. These studies were performed in 2007 and then reconfirmed in 2008 and evaluated the system for existing load levels up to a 10 year forecasted load level.

Included within both of these evaluations were testing of both N-1 and N-1-1 design criteria to comply with NERC TPL Standards, NPCC Document A-2, NYSRC Reliability Rules and the The Company Transmission Planning Guide (TGP 28). These standards require the entire transmission system to meet N-0 and N-1 voltage, thermal and stability criteria and the bulk power system and long lead time items to meet the same criteria for N-1-1 conditions.

Several reliability criteria violations for the area were discovered under study conditions. Violations include thermal overloads on 115kV circuits in the Central region for N-1 and N-1-1 conditions.

For further details refer to Exhibit 11.

Customer Benefits:

Customers will benefit from this program in several ways, including:

- Their exposure to service interruptions (some resulting from load shedding) in the event that certain key contingencies were to occur will be reduced significantly.
- Avoidance of "must run" units being created to alleviate post-contingency violations.
- Some capability to accommodate new or expanding load will be added to the system.

Should the contingencies which cause the overloading of the Yahnundasis-Porter line occur prior to this project, the result would be shedding of load in the Yahnundasis area. This project would eliminate the potential for that solution to be needed, improving the reliability of the system in that area, and reducing interruptions due to load shedding.

Customers in central New York will benefit from the reduced vulnerability of the transmission system due to these disruptive contingencies. Additionally, some capability to accommodate new or expanding load will be added to the system.

2009 and 2010 Variance Explanation:

This is a new project that was not included in the 2009 CIP.

Table II-11
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	-	-	300,000	1,600,000	1,600,000	3,500,000

D. Asset Condition Programs

Asset condition programs are focused on:

- Improving system reliability
- Reducing the likelihood and consequence of equipment failures
- Mitigating the possibility of environmental damage from leaks or emissions from assets
- Minimizing the likelihood of injury to the public and employees

Programs in this category include the 3A/3B strategy, relay replacement, flying ground strategy, RHE circuit breaker replacement, overhead line refurbishments and substation rebuilds.

3A/3B Tower Strategy

The 3A/3B Towers program was established following a 2003 tower failure. This failure resulted from an extreme longitudinal wind load generated by a storm. Phase I of the program (completed in January 2009) was the replacement of 139 transmission towers that were in service at road crossings and that support the Edic-New Scotland 14 345kV line. The remaining Type 3A and 3B towers on this line will need to undergo periodic climbing inspections to confirm the integrity of these structures.[18] The Company has four other 345kV lines that use these same types of towers. They are the 345kV New Scotland–Leeds 93 and 94 lines, Athens-Pleasant Valley 91 and Leeds–Pleasant Valley 92 lines. As of 2009, these lines have not experienced any tower failures. Only the 3A and 3B towers that pose safety concerns (i.e., near public roads, railways, or navigable waterways) were replaced on the Edic-New Scotland 14 line. A similar program for the remaining four lines is proposed. The two projects included within this program are: "Leeds - Pleasant Valley 91/92 tower reinforcement" and "New Scotland – Leeds 93/94 tower reinforcement."

Drivers:

Failures of tower types 3A and 3B have occurred on the Edic-New Scotland 14 line since the line entered service. In October 2003 Structure 347, a 3A tower, failed. Two previous failures occurred on 3B towers, Structure 3 in 1977 and Structure 66 in 1992 (adjacent towers 63, 64, 65, 67, and 68 were damaged by the collapsed tower). These failures occurred on the Edic-New Scotland 14 line. Phase I addressed safety concerned on the Edic-New Scotland 14 line and has been completed. Phase II will address these four remaining lines after Transmission Planning and the NYISO reviewed the future load needs associated with them. This is expected to be completed in calendar year 2010. Refer to the Type 3A-3B Tower Replacement Justification Document in Exhibit 12 for further discussion.

Customer Benefits:

The scope this program is being developed with consideration of the overall risks to public safety as the primary driver with improved reliability being a secondary benefit. The Company chose public safety as the main criterion for replacement because it determined that a limited replacement would utilize customer funds judiciously while correcting a potential public safety risk.

Thus, The Company has limited the program to those towers which pose the greatest risk to public safety:

- towers adjacent to road crossings
- towers adjacent to railroad crossings

[18] The 3A/3B Tower Strategy (SG 032) was included as Exhibit 21 in Volume 6 of 9 of the September 17, 2007 Transmission Capital Investment Plan, Case 06-M-0878.

- towers adjacent to navigable waterways, and
- towers replaced to reduce excessive cascading potential
- towers at transmission line crossings

2009 and 2010 Variance Explanation:

The Company and the NYISO are reviewing the future load needs associated with the 345kV New Scotland–Leeds 93 and 94 lines, Athens-Pleasant Valley 91, and Leeds–Pleasant Valley 92 lines. This is expected to be completed in calendar year 2010. If no load changes are anticipated for these lines, this safety driven project will proceed; if changes are anticipated the project will be re-evaluated. The increased costs reflect the experience gained on the Edic-New Scotland 14 work.

Table II-12
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	130,000	100,000	6,000,000	14,000,000	0	-	20,100,000
2010 CIP	-	-	50,000	150,000	6,100,000	41,000,000	47,300,000

Relay Replacement Strategy

This Strategy and program identifies relay replacement candidates based on (a) poor condition or historical poor performance (including relays within the same family) or (b) obsolescence where parts or knowledge are no longer available. Specifically, the scope includes about 650 high priority relays to be replaced in the next five years. In cases where a large number of relays are to be replaced in a control house that is itself in poor condition, the entire control house may be replaced including all relay packages contained within. There are three projects within this program that amount to over $2 million. The primary project represents the first phase of the “NY protection and control replacement” project.

Drivers:

This strategy is driven by the need to ensure that reliable protective relay systems are in place to preserve the integrity of the transmission system during system faults.

As discussed in the 2009 Asset Condition Report, the transmission system is protected by 8,000 relays. Approximately 6,500 are electro-mechanical or solid state types (Table II-13). Many electro-mechanical and solid state relays are at or near their end-of-life. Therefore, a replacement plan targeting the worst performing or obsolete relay families is required before equipment failure occurs.

Table II-13.
Count of Relays by Design Type

Design Type	# of Relays	% of Total
Electromechanical	6,240	78%
Solid State	287	4%
Microprocessor	1,439	18%
Total All Relays	7,966	100%

Phase 1 of the relay replacement strategy targets approximately 10 percent (about 650 relays) of the electro-mechanical and solid state relay population.[19] These relays have been evaluated by the Company's technicians and are either in poor condition, have a poor performance record, or lack the spare parts and the necessary knowledge needed to guarantee correct operation.

While in the longer-term thousands of electro-mechanical relays may need replacement based on a simple life cycle analysis (8,000 divided by an average life of 20 years would suggest a replacement rate of 400 relays per year), currently the Company has identified an immediate need to replace only the worst 650 relays.

In the early years of the strategy, a certain amount of "like-for-like" (using modern equivalent) relay replacement will still be required to address known problematic relay families (e.g., CEY, CEYG, GCY, etc). Beyond this (in Phase 2), an integrated protection and control replacement philosophy is envisaged, using pre-built, pre-tested replacement relay rooms that can be deployed quickly and cheaply. Second phase sites will be undertaken starting in FY14/15. Further details can be found in Exhibit 13.

Customer Benefits:

The benefit of this strategy will be increased reliability of the transmission protection and control system where known poor performing relays are replaced with microprocessor based relays. Protective relays that are functioning properly are essential to a rapid isolation of faults on the system, protecting customers from potential outages and protecting equipment from damage. The new relays will yield additional operation data that was not previously available, which will allow better analysis of system failures to prevent reoccurrences.

2009 and 2010 Variance Explanation:

The difference between the 2009 capital investment plan and the current forecast is that the project has been re-phased to provide a smoother replacement profile.

[19] Report on the Condition of Physical Element of Transmission and Distribution Systems, October 1, 2009, Table III-46, pg. III-64.

Table II-14
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,510,000	7,173,000	8,950,000	4,100,000	6,700,000	-	26,923,000
2010 CIP	-	50,000	1,000,000	3,750,000	6,450,000	14,850,000	26,100,000

Flying Ground Strategy

Flying ground switches are currently utilized as transformer protection devices and were manufactured by Haefely Trench and Delta Star. This program will replace all seventeen flying ground switches that are in service in the Western New York area, as well as two flying ground switches at Trinity Station in the Albany area with new circuit switches.

Drivers:

This project is driven by the need to improve reliability, to ensure the safety of personnel and to prevent damage to equipment.

The existing flying ground switches have reached their end of useful life and require replacement. The flying ground switches were installed in the mid to late 1950s and over time their operating speed has decreased because of worn linkages and other mechanical components. Due to this wear, there is a higher probability of equipment mis-operations or even inability to operate the equipment. Replacing the flying ground switches with new circuit switches will provide both switching and fault interrupting capabilities.

The failure of a flying ground switch to operate correctly may cause a significant delay in clearing a fault with disruption to customers as a consequence. Slow fault clearance could also result in a more sustained fault, leading to significant equipment damage, potential safety issues and longer customer outages. The replacement with modern circuit switchers will reduce the likelihood of such issues.

Refer to Exhibit 14 for further details of this program.

Customer Benefits:

Replacing the flying ground switches with a circuit switcher meets modern protection requirements and provides both switching and interrupting capabilities. Installation of these capabilities results in an overall improvement to system reliability. In addition to reliability improvements, there are safety improvements for site personnel to be realized through this program.

2009 and 2010 Variance Explanation:

This project was approved in November 2009. The revised cost estimates reflect the conceptual engineering forecasts. Preliminary engineering is now underway on this project.

Table II-15
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	250,000	1,250,000	2,500,000	2,500,000	-	-	6,250,000
2010 CIP	-	-	-	250,000	1,000,000	2,000,000	3,250,000

RHE Breaker Replacement

The Company discussed many issues with circuit breakers in its 2009 Asset Condition Report.[20] As part of its filing, The Company identified RHE Breakers as a specific issue. This program includes the replacement of Federal Pacific RHE oil circuit breakers (OCBs) at Oneida and one at Lighthouse Hill (R50, R70 and R60 respectively). The two projects within this program are "Lighthouse Hill" and "Oneida".

Drivers:

Circuit breakers cannot be allowed to become unreliable due to the key functions they perform, particularly fault clearance. The Federal Pacific type RHE circuit breakers are in poor condition, have a history of failure, lack adequate spare parts and have experienced mechanism, bushing, and interrupter problems.

The possibility of these breakers failing during fault interruption duty is increasing. There have been three RHE failures at the Rotterdam Station (R23, R24 and R84), even though prior diagnostic inspections provided no indication of imminent failure. Equipment failures at high voltages (115kV and above) have the potential to be extremely dangerous, resulting in erratic voltage dissipation and flying debris. In many cases, adjacent equipment is damaged, further increasing the risk of injury and customer outages.

Environmental concerns associated with oil filled equipment failures are also an issue. RHE circuit breakers contain 1500+ gallons of oil and there have been cases where similar circuit breaker failures were powerful enough to rupture the tank, causing extensive and costly environmental clean ups.

Customer Benefits:

The planned replacement of these circuit breakers reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages. Implementing this strategy also addresses the need for reliable fault interruption capability for the safety of our employees and equipment. Refer to Exhibit 15 for further details.

[20]Ibid, pgs.III-43 to III-48.

2009 and 2010 Variance Explanation:

The $2.4 million decrease in the RHE replacement program is offset by an increase in spending in the Substation Rebuild program caused by the change of scope at Rotterdam.

Table II-16
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,370,000	1,959,000	-	-	-	-	1,959,000
2010 CIP	-	100,000	329,000	500,000	-	-	929,000

Substation Battery Replacement

Battery and charger systems are critical components that are needed to ensure substation operational capability during both normal and abnormal system conditions. The intent of the Battery Replacement Strategy is to replace battery and charger systems that are 20 years old (allowing for an extra five years if the battery system tests in good condition). The 20 year limit is based on industry best practice and experience in managing battery systems.

Drivers:

Presently, there are approximately 260 battery sets installed, with 15 sets in excess of 20 years and another 71 sets that will become over 20 years old between 2009 and 2014.[21]

Common end of life failure modes are positive grid corrosion and electrolyte dilution. These failure modes are inherent in the design, inevitable and irreversible.[22]

Most of the 115 kV substations in New York have a single substation battery system. There have been at least three instances in the last five years where a connection problem (that would have prevented substation equipment to operate when needed) was found during annual battery maintenance. Further details are provided in Exhibit 16.

Customer Benefits:

This program provides for the proactive replacement of battery systems at end of life, minimizing the risk of battery system failure. A battery system that does not perform adequately could result in serious reliability consequences, thus impacting customers.

[21] Report on the Condition of Physical Element of Transmission and Distribution Systems, October 1, 2009, pg. III-58.
[22] David Linden and Thomas B Reddy, Handbook of Batteries, McGraw-Hill, New York, 2002

2009 and 2010 Variance Explanation:

Project C32957 (i.e. Battery Replacement) was not previously included in the 2009 CIP filing. This is a recurring program that will replace station batteries and chargers at 20 years.

Table II-17
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	337,460	-	-	-	-	-	-
2010 CIP	-	1,206,000	1,206,000	626,000	626,000	626,000	4,290,000

Shield Wire Strategy

This major program concerns the replacement of shield wire on 408 miles of 115 kV transmission lines or approximately nine percent of the total 115 kV mileage in The Company's New York transmission system. The overhead assets targeted by this program are referenced in the 2009 Asset Condition report.[23] Two projects within this program amount to over $2 million, with the largest being the Gardenville-Homer 151/152 project.

Drivers:

The primary driver of this Strategy is enhanced reliability of the transmission system. In FY09, shield wire failure accounted for approximately eight percent of the total number of sustained outages (up from six percent in 2007). These outages were caused by a number of elements including lightening strikes and events that cause structural imbalance such as heavy wind, splice failures, ice loading and other related events.

Shield wire serves as a grounding element deflecting the lightning strikes away from energized conductors and conveying it to ground without permitting flashover to occur. A well grounded shield wire system significantly reduces the likelihood of an outage due to a lightning strike.

In addition to lightning protection, the shield wire provides critical support against imbalance caused by heavy wind, conductor drop or failure, splice failure, localized wind shear, ice loading and other related elements.[24] These imbalances occur more often than originally suspected and as long as the shield wire system is intact, they go unnoticed. An intact sound shield wire will help minimize structural related outages.

Safety is also a major factor when dealing with shield wires. A dropped shield wire that goes unnoticed (no outage) creates a major safety concern to the public. In one such past

[23] Ibid, pgs. III-26 to III-35.
[24] In future the Company will consider the installation of Optical Groundwire (OPGW) during replacement of shield wire where cost beneficial.

instance of a dropped shield wire, the adjoining land owner coiled the shield wire and attached it to the leg of a 115 kV lattice tower with the line still energized.

Customer Benefits:

The planned program targets reliability improvements of the 115kV transmission system by reducing the total duration of sustained outages by over 2,000 minutes/year.

There will also be a benefit in the improvement in the performance of each circuit. Even those shield wire failures that go unnoticed generally require a scheduled outage for repairs. Consequently, the reliability of the circuit suffers as do those customers served.

The replacement of the shield wire system on those lines listed in Exhibit 17 will improve reliability and reduce significantly the risk of an injury due to shield wire failure.

2009 and 2010 Variance Explanation:

Capital spending has commenced within FY09/10 on the Dupont-Packard, LaFarge, Mountain-Lockport and Huntley-Lockport shield wire replacement projects. Therefore, the spending of this $13m does not show up in the FY10/11 – FY14/15 forecast.

Table II-18
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	13,265,000	10,665,000	4,455,000	-	-	-	15,120,000
2010 CIP	-	8,168,000	7,160,000	-	-	-	15,328,000

Steel Tower Strategy

This program will address steel towers whose condition no longer meet requirements defined in the Strategy.

Drivers:

New York Public Service Commission Order (Case 04-M-0159) effective January 5, 2005, directed Niagara Mohawk to ensure that the Company's transmission lines meet the governing National Electric Safety Code (NESC) under which they were built. The order instructed the Company to replace wood poles and steel structures that no longer meet the governing code requirements. There are 20,325 steel structures (17,448 towers and 2,877 poles) in service across Niagara Mohawk's service territory.[25]

[25] Report on the Condition of Physical Element of Transmission and Distribution Systems, October 1, 2009, pg. III-10.

At the time the Steel Tower Strategy was written, four failures of steel structures were attributable to poor condition and since the Strategy was written, another failure occurred. For details on the failure incidents, refer to the 2009 Asset Condition Report.[26]

Due to the deteriorated condition of certain of these facilities, a serious safety and reliability concern exists as shown in the table below.[27] Although all voltage levels were initially examined, the towers on the 115kV transmission lines are the main concern.

Table II-19.
Steel Structure Visual Grades (as of October 2009)[28]

Visual Grade	Number of Assets	Percentage
1	8,689	49.61%
2	3,396	19.39%
3	3,703	21.14%
4	1,339	7.65%
5	380	2.17%
6	6	0.03%
Total	17,513	100.00%

Customer Benefits

Outside of the indirect reliability benefits, public safety is the main benefit of the Steel Tower Strategy. By replacing deteriorated structures adjacent to roads, railroads, and navigable waterways, public safety is enhanced. Secondly, by replacing structures not near crossings the remaining safety concerns caused by deteriorating structures are addressed.

If the structures with “sound rust” are painted using a quality priming system and finishing coat, it is reasonable to expect that life could be extended by an additional 10 years.

2009 and 2010 Variance Explanation:

The Overhead Line Refurbishment Strategy was approved in March 2008. This Strategy began a major asset replacement program over a twenty-five year period. The present phase of the Strategy focuses on refurbishing circuits that fall within the 40 worst performing circuits. This approach targets both wood pole and steel structure lines. The Overhead Line Refurbishment Strategy will absorb longer-term steel tower replacement projects that were previously planned under the Steel Tower Strategy. This explains the $19 million variance between the 2009 CIP and this filing.

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[26] Ibid, pg. III-14
[27] Ibid, pg. III-14.
[28] Ibid, pg. III-11 (see Table III-11 for explanation of visual grades).

Table II-20
Program Variance ($)

	FY 09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	14,364,154	9,261,000	275,000	125,000	125,000	-	9,786,000
2010 CIP	-	4,500,000	350,000	-	-	-	4,850,000

Substation Rebuilds – Gardenville, Dunkirk and Rome

There are six stations currently being closely studied for either upgrades or rebuilds to better meet the current and future needs of the transmission system and its users: Gardenville, Dunkirk, Rome, Rotterdam, Lockport and Lighthouse Hill.

Drivers:

Each of these stations has been identified as having asset condition and/or configuration issues that may result in the need for a major station rebuild or upgrade.[29]

Gardenville

The station is a 230/115kV complex south of Buffalo. It has two 115kV stations in close proximity that are referred to respectively as New Gardenville and Old Gardenville, and which both serve regional load. New Gardenville was built between 1959 and 1969 and has asset issues such as faulty control cables, deteriorated foundations and many disconnects have deteriorated beyond repair. Old Gardenville, built in the 1930s, feeds regional load via eleven 115kV lines. The station has serious asset health issues including, but not limited to, control cable, breaker, disconnect and foundation problems. The station has had no major updates since it was built. There have been a number of mis-operations that can be directly attributed to control cable issues in the past several years alone. Because of this, a project has been initiated that addresses these issues by completely rebuilding both 115kV portions of this station. The new 115 kV switchyard will be constructed in the western section of the site and there will be rerouting of approximately twenty 115 kV lines for the project. Project Sanction is expected in the fall of 2011.

Dunkirk

This station is a 230/115kV station located south of Buffalo, connected to 522MW of generation owned by NRG. The Company retains ownership of most of the 230kV and 115kV switch yard; however, the controls are located in the generation control room owned by NRG. This station has recently experienced several 230kV mis-operations due to control

[29] See "Report on the Condition of Physical Elements of Transmission and Distribution Systems," October 1, 2008, Exhibit 2, p. V-66 (Upstate NY Asset Health Report for Transmission. at p. 62, section 6.8.2) and "Report on the Condition of Physical Elements of Transmission and Distribution Systems," October 1, 2009, Page III-68 through III-77.

cable issues as detailed in the 2009 Asset Condition report.[30] Complete replacement of control cables is not possible due to space constraints in shared areas. In addition, portions of the station may be deemed “bulk power” requiring significant modification.

There are parallel efforts underway to address these issues. In the short term, a project has been approved to install a new cable trench in the 230kV yard in 2009. Control cables deemed faulty can then be replaced using these new facilities. In the long term, conceptual engineering is underway to construct a new control house and completely separate assets in this station. In addition, other equipment, such as disconnects and PTs deemed to be at end of life will be replaced during a project to install a second bus tie.

Rome

The Rome station was constructed in the early 1920s. It has received several reconfigurations over the years with the current 115kV to 13.2kV dual bus built in the early 1970s. The 115kV system at the Rome Station experiences periods of low voltage particularly if the tie-breaker is opened. Station property near the north bus section has been under environmental remediation the past several years due to a former coke plant that was located on the site. Assets located on the North yard will be relocated away from this remediation site.

There are multiple asset condition issues affecting the station noted in the 2009 Asset Condition Report:[31]

- 115kV disconnects are degraded and often break upon operation
- 115kV instrument transformers were built in the 1930s and have weakened foundations
- Batteries and chargers have failed during bus outages
- Asbestos was found in the control house, deteriorated windows, doors and inadequate lighting making it unsafe and a liability
- the steel structure for the North bus is heavily corroded with degraded footings

A Strategy paper proposing a station rebuild was Sanctioned in October 2009 and Preliminary engineering has started.

These three stations are at various stages of engineering for either an upgrade or rebuild to better meet the current and future needs of the transmission system and its users.

For further information on drivers refer to the Station Rebuild Program (Gardenville, Dunkirk, Rome) Justification Document in Exhibit 19.

In addition to the Gardenville, Dunkirk and Rome stations, Rotterdam (230kV, 115kV69kV, 34.5kV and 13.2kV)[32], Lockport (115/12kV) and Lighthouse Hill (115/12kV)

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[30] Report on the Condition of Physical Elements of Transmission and Distribution Systems,” October 1, 2009, Page III-70.

[31] Ibid, pg. III-71 and III-72

[32] See also the reference to Rotterdam 230kV in the RHE Replacement program.

have been identified as having asset condition and/or configuration that indicate a need for a major station rebuild or upgrade.

Rotterdam

Rotterdam is a large station with 230kV, 115kV, 69kV, 34.5kV and 13.2kV sections spread out over multiple tiers on a hillside. The 230kV yard is the main source for Schenectady. Rotterdam is supplied from the Porter Lines #30 and #31 and from Bear Swamp on the E205 line to Massachusetts. As discussed in the 2009 Asset Condition Report, the 230kV yard has had performance issues and there have been three (R23, R24 and R84) catastrophic failures of Federal Pacific Electric RHE breakers. Two of the three 230kV auto transformers at Rotterdam are also proposed for replacement. The #7 and #8 transformers have a higher than normal failure likelihood due to their design specifically due to "T" beam heating and static electrification. There has also been an issue with capacitor bank #4 tripping off line on differential protection if capacitor bank #3 is put into service while capacitor bank #4 is on line.[33]

Given the extent of the asset condition issues discussed above and the need for upgrades at the station due to the Northeast Region Reinforcement Project (Luther Forest)[34], the Rotterdam substation will be rebuilt

Further work is currently ongoing at Rotterdam, to better identify the actual scope of work and possible options, which may include a new 230kV site on level ground, a 230kV GIS substation or a 345kV option.

Refer to Substation Rebuild Program Justification Document in Exhibit 20 for more details on the drivers for this program.

Lockport

Lockport is a major 115kV transmission station with thirteen 115 kV transmission lines tying through the East and West bus sections. This station is critical to the 115kV system operations of Western New York. The overall condition of the station yard and control room is poor. As discussed in the 2009 Asset Condition report, work is required on control cable duct banks, breaker operators, structure painting and concrete equipment foundations that are deteriorated significantly. In addition, support column and breaker foundations are in a deteriorated condition and need to be repaired with several potentially needing full replacements.[35]

There are two new 115kV SF_6 breakers at Lockport, while the remaining 115kV oil filled BZ0 breakers show exterior corrosion and oil leaks. Three of the 115kV oil breakers

[33] Report on the Condition of Physical Elements of Transmission and Distribution Systems," October 1, 2009, Page III-73 and III-74.

[34] See Appendix 1, page 13 of the Company's Petition to Defer Electric Transmission and Distribution Investment Costs (Case 07-E-1533 filed April 21, 2009).

[35] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878 October 1, 2009, Page III-74 to III-76.

have hydraulic mechanism leaks common to the BZO style breakers and failures of hydraulic system components have been increasing. Each of the BZO breakers also has bushing potential devices which have been another source of failure.

The control room building is also in very poor condition with increasing costs to maintain the original roof and the intricate brickwork.

Given the number of transmission lines at the Lockport Station and the deteriorated conditions of the structures and controls that support them, a station rebuild is proposed to prevent future outages caused by equipment failures.

Lighthouse Hill

This facility is a significant switching station. It has two 115kV buses and seven transmission lines connecting to the station allowing power to flow from the Oswego generating complex to the Watertown area in the north and Clay Station in Syracuse. In addition, the station provides a direct source of off-site power and black start capability to Fitzpatrick Nuclear Station.[36]

The disconnect switches are in a very poor and hazardous condition, with insulators failing constantly.

Seven OCBs are located 200 feet from the Salmon River located about 70 feet below the yard elevation. The station is located a mile up-stream of the New York State Wildlife Fish Hatchery. Although the risk is low, any significant oil spill in the station would have a detrimental environmental impact. There is also the risk of a flooding event at the station given its proximity to the river.

Another significant issue at Lighthouse Hill is that the land is owned by Brookfield Power and operated as a shared facility under a contractual agreement. The lack of direct access to Brookfield's control room at Lighthouse Hill is not ideal as it limits the Company's control over the housing conditions for the battery and relay systems. The Company has controls on the first floor of the control house which is immediately adjacent and downstream of Brookfield's hydroelectric dam. A release from the dam would likely flood the control room area.

Options currently being considered are a new substation located on the opposite side of the adjacent road in the clearing near the transmission right-of-way to eliminate the risks of oil contamination to the Salmon River and reduce the likelihood of station flooding.

Customer Benefits:

The planned replacement of these stations reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

[36] Ibid, pg. III-76 to III-77.

2009 and 2010 Variance Explanation:

New Scotland, which had been as one of the stations with possible configuration issues, has been dropped from consideration for a major rebuild. The most recent NERC N-1-1 studies have indicated that the configuration of New Scotland is adequate. In addition, there are no urgent asset condition issues.

The table below also includes all of the substation rebuild projects listed in the sections above. The 2009 CIP also included circuit breaker replacement projects that have either been reclassified as part of the Circuit Breaker Replacement Strategy, cancelled or included in other asset condition.

Table II-21
Program Variance ($)

	FY 09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,000,000	23,350,000	52,500,000	45,300,000	101,250,000	-	222,400,000
2010 CIP	-	2,795,000	8,906,000	58,855,000	68,860,000	66,184,090	205,600,090

U Series Relay Strategy

The Westinghouse U series line of relays was introduced in the early to mid 1970s and production and support for these relays ceased in the mid 1980s. Westinghouse U series Relays are at or near the end of their useful life and installed on a number of important 345kV lines in New York. The replacement of these relays with new technology presents significant advantages such as enhanced reliability, improved protection systems and the ability to record operational data for system performance analysis. There are four different projects within this program including replacing relays at the Leeds and Edic Stations.

Drivers:

Replacement parts and support for the Westinghouse U Series Relays are no longer available making continued maintenance of these devices difficult. Spare parts harvested from previously failed units have been depleted. Procurement of spare parts from outside sources is not an option.

An un-repairable U Series Relay could be out-of-service for an extended period of time before a replacement relay can be installed. This situation would leave the transmission line with a single system of protection for a prolonged period of time. This could have a significant impact on the reliability of the interconnected power system as the circuit would either have to be taken out of service or the power system would have to be run with a constraint to minimize the impact of a single protection failure out side of the local area.

The new relays consolidate many relay functions into a single package, reducing the need for multiple relays to protect a single line. They also have the capability to record information at the time of a power system event, enabling enhanced post event analysis that can lead to improved protection system performance. Further details are provided in Exhibit 21.

Customer Benefits:

This program will improve the overall dependability of the protection system. The replacement relays will have the capability of providing fault and operational data which is currently not available. This data can be used in the future when it comes to analyzing and improving the system as a whole. Both of these factors will have a positive impact on customer reliability.

2009 and 2010 Variance Explanation:

The U Series Relay replacement has been assessed along with the Relay Replacement Strategy mentioned above. The difference between the 2009 and 2010 CIP is accounted for by the spend in FY09/10.

Table II-22
Program Variance ($)

	FY 09/10	FY 10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	690,177	2,350,000	500,000	-	-	-	2,850,000
2010 CIP	-	2,300,110	663,000	-	-	-	2,963,110

Overhead Line Refurbishment Program

The basic level of this program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built. This will be accomplished through the replacement of deteriorating structures and line components that no longer structurally or electrical adhere to the governing NESC. There are 15 projects over $2 million within this category including the refurbishment of many of the ‘worst performing lines’ such as Lockport-Mortimer 111, 113 & 114, Lockport-Batavia 112, Taylorville-Mosier 7, Dunkirk-Falconer 161/162, Gardenville-Dunkirk 141/142 and Gardenville-Homer Hill 151/152 projects.

Drivers:

The Company has over 6,000 circuit miles of Transmission overhead lines and many of these overhead line assets are approaching, and some are beyond, the end of their anticipated lives. There are two main drivers for the proposed long-term overhead line refurbishment program. Firstly, the program will ensure that the Company’s transmission lines meet the governing code under which they were built as required by the Commission’s 2005 Safety Order (Case 04-M-0159). Secondly, the program will improve the reliability transmission system by rebuilding the worst performing lines.

The Overhead Line Refurbishment Strategy (Strategy approved in March 2008) assures that the Company's transmission lines meet the governing National Electric Safety Code (NESC) under which they were built. This will be accomplished through the replacement of deteriorating structures (both wood and steel) and line components that no longer structurally or electrically adhere to the governing National Electric Safety Code. This will be done on a line-by-line basis and will follow an in-depth condition assessment and engineering evaluation of the lines.

Candidates for refurbishment will be selected based upon five factors:

- The five-year average reliability statistics as published in the Transmission Network performance Report or any circuits that appear in the SGS Statistical Services benchmarking list of worst performing 100 circuits
- The condition as determined by field inspection, testing and analysis
- Age distribution figures for overhead line assets in New York show an aging population. A significant proportion of the Company's steel structure assets were installed between 1899 and 1939 (70 – 110 years old) and a large population of wood poles were installed between 1909 and 1985 (25 to 100 years old). A recent evaluation of the performance of 115kV lines against age demonstrated a strong correlation between age and decreasing reliability. Hence increasingly aged populations of overhead line assets present the Company with a reliability challenge
- Whether the line consists of steel or wood structures
- Risk and criticality i.e. the Line Importance Factor which ranks lines based upon the consequences of failure and the part the circuit plays within the integrated transmission system

The final selection of lines will also consider other additional factors such as outage availability, bundling to create economic packages of work, interaction with other strategies and projects, etc. For more detailed information on these drivers refer to Exhibit 22.

Customer Benefits:

This program assures that transmission lines meet the governing NESC under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the Code.

2009 and 2010 Variance Explanation:

The overall variance between the two capital investment filings is due to the spending already incurred in FY09/10, some conceptual level re-phasing of the Strategy, and the inclusion of additional expenditures in FY14/15 due to better project scopes that were developed and defined once preliminary engineering was completed.

Table II-23
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	10,711,666	29,399,200	58,087,400	80,414,400	75,421,000	-	243,322,000
2010 CIP	-	20,185,000	32,515,000	53,700,000	92,000,000	77,850,000	276,250,000

Transformer Replacement Strategy

This strategy targets replacement of the 39 highest priority transformers based on condition and performance assessment. The scope includes ancillary equipment (i.e., radiators, fans and pumps), associated civil works, surge arresters and bus connections.

Drivers:

The 2009 Asset Condition Report provided a number of condition and performance issues.[37] The unplanned failure of a transformer can lead to customers being out of service for long periods of time until the load can be switched or until a mobile substation can be delivered and installed. Internal transformer faults can result in explosions and fires. Some transformers do not have oil containment and in the event of a catastrophic failure an oil spill would occur.

The replacement rate of transformers over the past 10 years is insufficient to avoid a "wall of required" replacements. By 2020, of the population of 508 transformers there will be more than 150 transformers over the age of 55 (anticipated asset life) including 57 transformers over the age of 80.[38]

Customer Benefits:

This is a pro-active end of life management strategy to ensure the overall reliability of the transmission system. It is estimated that the failure of just one average 17MVA sized transformer could lead to a loss of power for approximately 17,000 residential customers. The prolonged time needed for restoration (either through the installation of a spare or a mobile sub) would translate into millions of customer minutes interrupted.

2009 and 2010 Variance Explanation:

In the 2008 Asset Condition filing, the Company identified 16 Priority 4 transformers for replacement along with a further 110 Priority 3 units. The Company has refined this list to include 39 Priority 4 units based on analysis of DGA results, electrical test results and family

[37] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878 October 1, 2009, Page III-51 to III-56.
[38] Ibid, pg. III-50.

history.[39] The latest list of candidates is included in the Exhibit 23. In addition, revised cost estimates based on recent procurement events and an assessment of deliverability have resulted in a revised forecast spend profile shown in Table II-24. Overall, the forecasted cost for the replacement of the 39 worst transformers is between $90 million and $110 million. These estimates are based on an average cost of approximately $2 million per transformer plus additional costs for related work such as additional civil work, replacement of PTs and disconnects.

Table II-24
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	800,000	7,700,000	13,200,000	26,000,000	30,000,000	-	76,900,000
2010 CIP	-	4,000,000	7,000,000	7,000,000	7,000,000	8,966,667	33,966,667

Circuit Breaker Replacement Strategy

The Circuit Breaker Replacement strategy will address problematic circuit breakers.

Drivers:

Improving reliability is the primary driver for this Strategy as 11 percent of sustained outages on the bulk system and 12 percent of sustained outages on the non-bulk system are caused by substation equipment including circuit breakers. Due to the key function carried out by circuit breakers, particularly for fault clearance, these assets cannot be allowed to become unreliable. The 2009 Asset Condition Report highlighted a number of issues related to circuit breakers.[40]

Safety is another driver for this program as circuit breaker failures have the potential to be extremely dangerous, resulting in erratic voltage dissipation and flying debris. In many cases, adjacent equipment is damaged, further increasing the risk of injury.

The avoidance of oil spills in the event of a failure is a further driver for replacement. Typical bulk oil circuit breakers contain 1500+ gallons of oil and incidents have occurred where the force resulting from the circuit breaker failure was powerful enough to rupture the tank causing extensive and costly environmental clean up.

The scope of this strategy is to install approximately 130 SF_6 (gas) circuit breakers over the next ten years (replacing high priority oil circuit breakers). Additionally, where cost effective and where condition warrants, the opportunity will be taken to replace disconnects, control cable and other equipment associated equipment.

[39] Ibid, pg. III-52.
[40] Ibid, pgs. III-45 to III-46.

Of the 130 oil circuit breakers, 37 are being replaced due to inadequate short circuit interrupting capabilities. The remaining ones will be replaced based on known condition issues. Further details are provided in Exhibit 24.

Customer Benefits:

The planned replacement of these 130 circuit breakers reduces the likelihood of an in-service failure which can weaken the transmission system and may lead to customer outages.

2009 and 2010 Variance Explanation:

Queensbury oil circuit breakers were identified separately in the 2009 CIP filing as candidates for replacement. These breakers have now been reassessed and their replacement is no longer considered a priority. Replacement spend has be re-phased to reflect outage availability, resource constraints and to smooth the expenditure profile.

Table II-25
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	250,000	1,200,000	20,100,000	10,170,000	-	31,720,000
2010 CIP	-	100,000	1,100,000	7,250,000	14,450,000	18,000,000	40,900,000

Polymer Insulator Replacement

The program will address concerns associated with the failure of polymer insulators due to moisture ingress.

Drivers:

The driver for the Polymer Insulator Replacement Strategy is the aim to improve reliability. As discussed in the 2009 Asset Condition Report, certain types of polymer insulators are prone to failures due to moisture ingress. When moisture penetrates the insulator's sheath and reaches into the fiberglass core, the result can be failure due to brittle fracture or flash-under (caused by tracking along or through the fiberglass rod).[41] The flash-under leads to a power arc and the unwanted removal from service of the affected line. In some instances, this can lead directly to customers being cut off from the supply and in all cases reduces the ability of the transmission system to withstand a subsequent contingency.

Customer Benefit:

Replacing the problematic polymer insulators will remove the possibility of outages caused by the failure of polymer insulators and hence improve future reliability performance.

[41] Ibid, pgs. III-35 to III-36.

2009 and 2010 Variance Explanation:

In previous years, the capital expenditure for this program was identified separately. However, the costs associated with polymer insulator replacement have now been included within individual overhead line refurbishment projects. The reason for this change is economic efficiency. Polymer insulator replacement is now completed coincident with other planned projects on the same circuits, rather than a "stand alone" project.

Table II-26
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,000,000	5,000,000	5,700,000	-	-	-	11,700,000
2010 CIP	-	-	-	-	-	-	0

Wood Arm Replacement Strategy

The Wood Arm Replacement Strategy has been integrated into other programs. This was tentatively placed into the 2009 plan as a result of wood pole cross arm failures. However, split timbered wood cross arms are primarily used. Wood horizontal pole cross arms tend to deteriorate faster than split timbered wood cross arms. While occasional failures have occurred, these have a relatively negligible impact on reliability and safety.

Going forward, the Strategy is to replace any type of wood cross arms with steel cross arms as structures are replaced or refurbished.

2009 and 2010 Variance Explanation:

As shown in the table below, the reason for the variance between the 2009 CIP and this filing is that the wood arm replacement will be done when wood structures are replaced either through the Overhead Line Refurbishment Strategy or the Wood Pole Management program. In addition, any wood cross arms showing signs of deterioration (i.e., splitting or rotting) during the periodic five year inspections will be replaced or repaired.

Table II-27
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	200,000	15,000,000	20,000,000	-	35,200,000
2010 CIP	-	-	-	-	-	-	0

Other Asset Condition

The other asset condition classification includes all of the smaller, typically lower cost, capital investment projects that do not fit within any of the longer-term major programs. Examples of other asset condition projects are surge arrester replacement (C31658), transformer replacements at Packard (C27006) & Gardenville (C27042), Leeds SVC refurbishment (C03748) and PIW (problem identification worksheet) driven projects (CNYX72). Together these six projects account for $40 million of the $55 million with a approximately 40 projects accounting for the remaining $15 million.

Surge Arresters

Drivers:

This program is one of the largest within the "Other Asset Condition" Program, totaling an amount of $7.93 million. It is driven by reliability, safety to personnel and the prevention of damage to other equipment during lightning or switching over-voltages. Tests conducted and reported by IEEE suggest that all silicon carbide arresters that have been in service for over 13 years should be replaced due to moisture ingress.[42]

There are approximately 700 surge arresters at 115kV and above installed. As discussed in the 2009 Asset Condition Report, up to 79 percent of all surge arresters are the silicon carbide type, with a large volume estimated to be over thirty years old. The Company experiences on average three surge arrester failures each year and the majority of the surge arrester failures are of the silicon carbide type. Typically these failures are contained to the surge arresters themselves, but on one occasion the failure of a surge arrester during a lightning strike led to the failure of a power transformer. As arresters are predominately installed on transformers, outage availability will limit this program and therefore replacement will be undertaken as damage/failure during normal planned maintenance.

The failure of a surge arrester can lead to damage to expensive wound equipment such as power transformers during switching or lightning transient over-voltages. This project will be undertaken in order to ensure that expensive equipment is adequately protected. Further details are provided in Exhibit 25.

Customer Benefit:

The replacement of low cost surge arresters will not only have a positive impact on finances (by avoiding damages to expensive equipment such as power transformers), but also on reliability, as it will prevent damage to wound equipment (thereby preventing outages too).

2009 and 2010 Variance Explanation:

The variance between the 2009 CIP and 2010 is accounted for by the delay in implementation of this project due to outage availability.

[42] Degradation was evident in 75 percent of arresters tested.

Table II-28
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	250,000	2,500,000	2,550,000	2,630,000	2,710,000	-	10,390,000
2010 CIP	-	-	25,000	2,725,000	2,550,000	2,630,000	7,930,000

Transformer Replacement – Packard and Gardenville:

Drivers:

The Packard and Gardenville Transformer projects are two out of the largest projects within the "Other Asset Condition" program. In addition to the proposed Transformer Replacement Strategy, these are General Electric 230/115kV transformers fitted with LR9 load tap-changers known to be in poor condition. The Dunkirk TB31 bank failed in October 2007 and was replaced. Four similar transformers were manufactured between 1957 and 1958 and are in-service at New Gardenville and Packard substations. The Packard TB3 bank indicates an upward trend in combustible gases and the decision to replace all four of these transformers has been approved.

These two projects are driven by reliability and the need to replace the worst condition transformers ahead of failure. Replacement will:

- minimize the safety risk to personnel
- reduce the likelihood of widespread system disruption and local losses of supply
- minimize the likelihood of environmental damage due to oil spillages
- maintain reliability of service for the benefit of customers

The Packard and New Gardenville transformers have a unique and unusual construction that makes field maintenance impossible and it is probable that all four transformers are subject to an un-repairable defect which has already caused failure in another identical unit. Failure of one or more of these units could have serious safety, environmental and network reliability consequences.

All four of these units generate moderate to high levels of combustible gases, which indicates internal overheating problems and is consistent with transformers that are approaching end of life. In addition, Packard TB3 has a similar gassing pattern to the failed Dunkirk TB31. Further details are provided in Exhibit 26.

Customer Benefits:

The planned replacement of these transformers reduces the likelihood of an in-service failure which in turn reduces the possibility of severe disruption to the Buffalo area network. The failure of the Dunkirk TB31 and Gardenville TB2 transformers led to major disruption of normal system operations, planned maintenance, and the Company's construction program. Therefore, avoiding this kind of disruption reduces the cost to customers in the long-term. In addition, the unplanned emergency replacement of any one of these transformers would undoubtedly be more expensive.

2009 and 2010 Variance Explanation:

A portion of the spending for the transformer replacements at Gardenville will now be transferred into the Gardenville Station Rebuild program. Only the procurement and physical placement costs of the transformers to the Gardenville site will be included as part of this project. The rest of the costs will be charged to the station rebuild.

For Packard, spending has already occurred in FY09/10. This will not be accounted for in this 2010 CIP which only looks at future spending levels.

Table II-29
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	13,101,000	6,845,000	-	5,430,000	5,510,000	-	17,785,000
2010 CIP	-	10,147,000	-	2,800,000	2,800,000	-	15,747,000

Problem Identification Worksheets (PIWs)

The Company employs a process called "Problem Identification Worksheets" to identify faults and defects with in-service equipment that are identified either through normal maintenance activities (often called 'follow-up' work) or through inspection routines (often called 'trouble' work). Typically the issues identified through the PIW process cannot be corrected immediately and require investigation, engineering analysis and solution design. These activities and the solutions proposed frequently lead to low cost (but not always) capital projects to replace or refurbish items of equipment.

Drivers:

Historically, issues identified during inspection or maintenance were added to the capital plan in outer years to avoid reprioritizing other planned projects. In 2009/10 a budgetary line for PIWs was introduced to recognize that a number of high priority, low cost, capital projects will inevitably arise during the year and these should be undertaken to address found-on-inspection issues.

Issues arising from PIWs are prioritized and engineering solutions for the highest priority are developed within year. Utilizing this approach, the Company can make progress on low cost capital investments that might otherwise be lost in the capital plan.

Examples of PIW driven projects are the replacement at Geres Lock of fourteen 115kV manual disconnect switches and the replacement at Harper Station of circuit switchers 2023 and 2024.

2009 and 2010 Variance Explanation:

This line item was added to the 2010 Capital Investment Plan. It captures the costs of capital replacement projects that are driven by defects found on inspection or through maintenance.

Table II-30
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	1,000,000	1,500,000	1,500,000	3,000,000	3,000,000	10,000,000

Leeds SVC Refurbishment

This project will replace five out of six major components that make up the Static Var Compensator (SVC) at the Leeds substation in New York. Work to be performed under this project includes the replacement of all components of the SVC that are unreliable, have limited or no parts availability, or are no longer supported by the manufacturer. The six components of the SVC that will be addressed are:

- Protection
- Control
- Trigger Pulse System
- Thyristor Valves
- Cooling System
- External Primary Devices

Drivers:

This project is required to address the decreasing reliability of the SVC and obsolescence issues. The Leeds Static Var Compensator (SVC), installed in 1987, has demonstrated declining reliability in the last six years. In February 2003, ABB the manufacturer of the SVC sent letters to Niagara Mohawk announcing the discontinuation of support for the SVC. This could lead to prolonged outages of the SVC. Replacement parts for these components are now completely unavailable. The proposed refurbishment work includes the replacement of all SVC components that are unreliable, have limited or no spare parts availability or are no longer supported by the manufacturer.

An assessment of reactive power support requirements at the Leeds Station was performed in 2005. The study found that loss of the SVC would de-rate the New York Central to East (NYCE) boundary flows by 100 MW. The Company reviewed and reconfirmed the study in 2006. A 100 MW reduction of the NYCE capability has the potential to raise wholesale electricity prices for customers. It would do so by increasing the number of hours of the year during which the interface becomes a binding constraint on power flows from lower cost generation located in Western and Central NY.

Since 2000, there have been over 45 documented problems with the SVC, requiring moderate to major maintenance. These problems have occurred mainly in the protection, control, trigger pulse and thyristor systems.[43] Many of these incidents have resulted in unexpected outages of the SVC, some for extended periods of time. These problems are likely to increase in frequency and severity going forward, thus resulting in an elevated risk of failure. This conclusion is also supported by the manufacturer. Further details are provided in Exhibit 27.

Customer Benefits:

As stated above, the Leeds SVC has demonstrated increasing unreliability in the past six years. The poor reliability has been especially acute in the protection, control, thyristors and trigger pulse systems. All of these components are no longer supported by the manufacturer and spare parts are dwindling. In addition, these systems are complex to a point where technical assistance is often needed to fix problems. Unplanned replacement could take over a year to engineer, procure and execute.

Table II-31
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	5,530,000	1,500,000	-	-	-	-	1,500,000
2010 CIP	-	5,854,000	-	-	-	-	5,854,000

E. Non-infrastructure Investment

There are four projects listed within this non-infrastructure investment category. The two main programs within the business plan period are part of a prospective project to address possible flood mitigation and a project requested by the NY PSC to enhance physical security at bulk power substations.

Physical Security

This program provides for the implementation of state-of-the-art security measures to deter and/or detect unauthorized access to the bulk power system substations. The security measures are intended to deter intrusion by the obviousness of the measures such as camera installations and card readers, while at the same time providing technology to detect intrusions and reporting them to a 24 x 7 security control center.

Examples of the proposed security measures are as follows:

[43] Leeds SVC Station Log

- Deployment or card reader technologies at selected locations at the targeted substations
- State-of-the-art video capabilities connected to remotely monitored cameras
- Remote control of certain lights to illuminate the area in case of intrusion
- 24 x 7 monitoring of the facility by a security control center

These measures will enhance the physical security at the targeted substations thus meeting the stated PSC expectations. There is one stand alone project within this program.

Drivers:

This Strategy is driven by the PSC recommendation to install additional physical security measures at Bulk Power System (BPS) substations.

The Director of Utility Security at the NY Department of Public Services strongly urged The Company to enhance physical security at its NY BPS substations pointing out an increase in unauthorized access incidents nationwide with sometimes fatal results.

Trespass into a substation facility where high-voltage equipment is located could result in injury or death to a trespasser who comes in contact with an energized piece of equipment. Alternatively, intrusion could result in electric system equipment being vandalized or damaged such that power is lost or system instability results.

The BPS substations are already in compliance with the relevant CIP requirements, including CIP-006-1a “Physical Security of Critical Cyber Assets”. CIP-006-1a seeks to provide “six walled” security around our critical cyber assets. For BPS substations, the six walls usually refer to the control house where the cyber assets are contained. Security measures under CIP-006-1a include card readers and cameras monitoring the ingress and egress points for the control house.

This Strategy will provide physical security measures in the substation yard between the six walls out to the outer fence which are not addressed in the cyber security project mentioned above.

With the deployment of technological solutions to deter or detect intrusion, it is the desired outcome that evident security measures will deter intrusion. Should an intrusion occur, the solutions deployed would detect the intrusion and initiate the necessary alarms.

Further details are provided in Exhibit 28.

Customer Benefits:

The benefits from this strategy arise from deterring and detecting unauthorized access to BPS substations. The benefits to customers include:

- Mitigation in loss of power flow or equipment availability through prevention of vandalism or theft
- Reduction in costs to replace equipment stolen or vandalized at the stations

- Reduction of risk to company personnel who could be working in an environment where equipment has been damaged or vandalized
- Prevention of lawsuits from people who are injured after entering the property illegally or without proper supervision

2009 and 2010 Variance Explanation:

This program was not included in the 2009 CIP.

Table II-32
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-0
2010 CIP	-	100,000	6,000,000	3,000,000	0	0	9,100,000

Flood Mitigation

A evaluation of the flooding risk has concluded that flooding events are likely to increase due to climate change and that further work is required to fully assess the risk to principal substations and identify possible mitigation measures.

The majority of the transmission system was designed and constructed between 1940 and 1960. Subsequent development has been incremental and generally in close proximity to original installations. In many cases substation facilities were by necessity constructed on low-lying land considered unsuitable for other developments (e.g. residential / commercial property). Flooding at sites such as Gardenville and Oswego has already occurred, as well as at sites along the Mohawk River Valley (e.g. June 2006 - St Johnsville and Inghams).

Drivers:

A survey of bulk power sites and a small number of load sites already known to be vulnerable indicated that flooding was a possibility and measures may be required to reduce the likelihood of the event or prevent loss should the event occur.

Table II-33
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
CIP 2009	-	-	-	2,000,000	1,000,000	-	3,000,000
CIP 2010	-	-	-	2,000,000	1,000,000	-	3,000,000

III. Sub-transmission System

This chapter describes the capital investment projects and strategies that The Company is pursuing on its sub-transmission facilities. The current five year plan is represented in Table III-1.

Table III-1
Sub-Transmission Capital Expenditure by Spending Category ($)

Spending Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Statutory/Regulatory	11,708,000	10,846,000	11,882,000	12,411,000	11,946,000	58,793,000
Damage/Failure	3,619,000	3,767,000	3,885,000	3,985,000	4,103,000	19,359,000
System Capacity & Performance	7,641,000	8,317,000	17,199,000	16,108,000	17,139,000	66,404,000
Asset Condition	25,032,000	30,070,000	25,034,000	32,496,000	38,812,000	151,444,000
Total	48,000,000	53,000,000	58,000,000	65,000,000	72,000,000	296,000,000

Details of the strategies and the projects included in the plan are provided in Exhibit 29 and 30 and described in the following sections.

The following are some accomplishments for The Company's sub-transmission system in 2009.

- Completed three miles of double circuit line refurbishment and pole replacement for Schuyler-Valley 21/24.
- Design completed and currently in construction for Rathbun – Labrador #39 Rebuild.
- Completed a mile of non-contiguous pole replacement and reconductoring for Lowville-Boonville #22 Rebuild.
- Completed all Line work for Rotterdam-Schoharie #18 Refurbishment.
- Refurbished four miles of line and replaced 120 poles for Shaleton-North Angola 856.
- Completed pole replacements for 45 two pole structures for Gloversville-Hill Street #3 Refurbishment.
- Approximately 2300 miles of sub-transmission line inspected

A. Statutory/Regulatory Strategies and Programs

Capital spend in this category are required to ensure that the facilities meet the minimum legal, regulatory and contractual obligations of the Company. Statutory/Regulatory work is not handled under a specific Strategy. Work in this category represents new business and public requirements, such as road widening. The work can be defined in "blankets" or in specific projects where individual jobs are over $100,000.

The projected investment is shown in the table below. As additional projects are identified through external requests in years FY11/12 through FY14/15, funds will be allocated as appropriate.

2009 to 2010 Variance Explanation

The spending shown in FY11/12 is for the reimbursement to NYPA as part of the Tri Lakes Agreement where upgrades to the sub-transmission facility have been built and are operated by The Company, but owned by NYPA until The Company assumes ownership. It was recorded in FY10 and thus is not entered in the CIP 2010 numbers.

Table III-2
Variance Summary ($)

	Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11-14/15
Public Requirements	**2009**	1,000,000	1,200,000	42,000,000	-	-	-	**43,200,000**
	2010	-	1,289,000	293,000	309,000	316,000	331,000	**2,538,000**
New Business	**2009**	500,000	-	-	-	-	-	-
	2010	-	819,000	553,000	574,000	595,000	615,000	**3,156,000**
Blankets	**2009**	386,000	396,000	410,000	421,000	435,000	-	**1,662,000**
	2010	-	-	-	-	-	-	-
Inspection & Maintenance	**2009**	-	-	-	-	-	-	-
	2010	-	9,600,000	10,000,000	10,999,000	11,500,000	11,000,000	**53,099,000**
Total	**2009**	1,886,000	1,596,000	42,410,000	421,000	435,000	-	**44,862,000**
	2010	-	11,708,000	10,846,000	11,882,000	12,411,000	11,946,000	**58,793,000**

The new program impacting this spending category is the “Inspection and Maintenance” program discussed below.

Inspection and Maintenance Program

The Company will inspect all electric line assets (Distribution Overhead, Underground, and Sub-transmission line assets) once every five years under this program. Each inspection will identify and categorize all necessary repairs (or asset replacement) against a standard and in terms criticality to improve the reliability of the network for customers.

There are three types of inspections conducted by the Company:

- Visual inspections of overhead, underground, and sub-transmission line
- Aerial assessments of sub-transmission lines
- Infrared inspections of overhead distribution mainline sections of the feeders and overhead terminations on underground facilities

This program will replace some of the existing strategies program work such as feeder hardening, potted porcelain cutouts, targeted pole replacements, miscellaneous overhead, miscellaneous underground, manholes, and vaults.

The Company will also perform annual elevated voltage testing per Order 04-M-0159 amended and effective December 15, 2008 on all facilities that are capable of conducting electricity and are publicly accessible, such as street lights.

This program incorporates elements of the 2009 CIP report which were identified separately in that report, including "Wood Poles", "Miscellaneous Overhead Equipment", and "Miscellaneous Underground Equipment".

Details are provided in Exhibit 31.

Drivers:

The 2009 Asset Condition Report details application of the Inspection and Maintenance program to both distribution and sub-transmission line assets.[44]

Over the past four years, almost one quarter of the SAIFI metric was due to interruptions along the distribution network caused by deteriorated equipment (sixteen percent), animals (three percent) and lightening (seven percent). Interruptions along the sub-transmission network accounted for another seven percent of SAIFI.

Customer Benefits

The approximate average annualized expected benefits for implementing the Inspection and Maintenance program would be a reduction of 0.02 in SAIFI and 2.64 in SAIDI.

The Inspection and Maintenance Program is designed identify and eliminate elevated voltage levels on the Company's facilities that are capable of conducting electricity and publicly accessible.

2009 to 2010 Variance Explanation

The inspection and maintenance program is replacing the prior programs of feeder hardening, targeted pole replacement, and overhead miscellaneous capital. The phase in of budgeting for I&M program in place of prior programs is expected in FY10/11 Funding for I&M was previously budgeted in the Asset Condition spending rationale.

Table III-3
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 –FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	9,600,000	10,000,000	10,999,000	11,500,000	11,000,000	53,099,000

44 Ibid, pgs. III-78 and III-95

Major Program Elements

The major elements are line based inspection and maintenance and underground cable based inspection and maintenance activities on a five year cycle. There is no specific activity identified at this point as work is performed based on inspection results of the 20 percent of the system inspected each year.

B. Damage/Failure Strategies and Programs

Damage/Failure category projects are those capital expenditures required to replace failed or damaged equipment and to restore the system to its original configuration and capability as a result of damage or equipment failure on an as-needed basis. The spending basis represents historical actual costs for damage to equipment or failures caused by storms, vehicle accidents, vandalism or deterioration. Most damage/failure occurrences are single structures events and are handled under blanket projects. Individual work orders are used to capture individual, small value, relatively high volume work that is of standard construction and scope, short duration, and limited to a maximum of $100,000.

2009 to 2010 Variance Explanation

This spending category was first formally budgeted in FY 2009/10. As available data has improved budget estimates have been revised.

Table III-4
Variance Summary ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,335,000	1,581,000	1,628,000	1,677,000	1,728,000	-	6,614,000
2010 CIP	-	3,619,000	3,767,000	3,885,000	3,985,000	4,103,000	19,359,000

C. System Capacity and Performance Strategies and Programs

System capacity and performance strategies and programs are designed to address loading and reliability issues. Strategies and programs in this category are in development. The formalization of these programs is expected to be ongoing, as additional data requirements are identified and met. Capacity Planning for Sub-transmission follows the same process as in Distribution, and is described in Chapter IV – Distribution System.

2009 to 2010 Variance Explanation

Total expenditures in this area over the budget period are described in Table III-5. As additional projects are identified in years FY10/11 through FY13/14, funds will be allocated.

Table III-5
Variance Summary ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	6,678,000	7,275,000	3,798,000	3,821,000	805,000	-	15,699,000
2010 CIP	-	7,641,000	8,317,000	17,199,000	16,108,000	17,139,000	66,404,000

The increase in the forecast represents a recategorization of funds identified in the 2009 CIP report as "Other" and the identification of some significant load related activities, including sub-transmission line sectionalizing and Buffalo Network reconductoring.

Sub-Transmission Automation

The Sub-Transmission Automation Strategy encompasses distribution automation ("DA") as well as SCADA for reclosers, fault locators, and switches; the interface of DA enabled line devices with the substation feeder breaker. It also encompasses the communication by these devices to each other and also back to central Operations Centers and database warehouses.

The objectives for using DA are to improve reliability performance, increase ease of operation, and provide additional data for operational studies. Initially, pilot projects will be run on lines that have historically been poor performers to determine the best approach for wide scale rollout in later years. The Company has installed DA "enabled" switches and replaced reclosers at the Boonville-Lowville 22 Line and the Mallory-Lighthouse Hill 22 Line as part of the pilot and plans to continue implementation of the Strategy.

The table below provides the budget for this program.

Table III-6
Variance Summary ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	500,000	1,000,000	2,000,000	4,000,000	5,000,000	12,500,000

Sub-Transmission Mobile Substations

Mobile substations are key elements for ensuring continued reliability and supporting the system during serious incidents[45]. Typically they are used in:

- Emergency response (to replace failed or distressed equipment while waiting for a replacement)
- Proactive maintenance at a single ended station (where otherwise supplies would need to be switched off)

[45] The Sstrategy for Mobile Stations and Substation Readiness are in development.

The projected investment is shown in the table below. As additional projects are identified in years FY10/11 through FY13/14, funds will be allocated as appropriate.

2009 to 2010 Variance Explanation

The spend for 2009/10 is in line with completing the Mobile Substation work in 2009/10. Consequently no budget has been identified for FY11 to FY15. A review of spare transformers and mobile stations is underway and will be completed during FY11 to underpin identification of need and possible future budgetary requirements.

Table III-7
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,300,000	2,000,000	-	-	-	-	2,000,000
2010 CIP	-	-	-	-	-	-	-

Sub-Transmission Reactors (Non-Transformer)

The Strategy for substation based reactors (non-transformer type) is to assess and characterize condition during substation "Visual & Operational[46]" Inspections; the approach identifies those units which have a degraded concrete structure; this is a well known issue with aged non-transformer reactors. The current budget for reactors (non transformer) is provided in the table below.

2009 to 2010 Variance

As additional projects are identified in years FY11 through FY15, funds will be allocated as appropriate. The majority of the budget in FY2009/10 ($1,611,000) was associated with a project to replace a number of reactors at the Seneca station. These replacements have been reviewed and deferred as the associated risk was such that other projects could be prioritized ahead of the reactors.

Table III-8
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,811,000	200,000	-	-	-	-	200,000
2010 CIP		-	-	-	250,000	1,000,000	1,250,000

[46] V&O Inspections are discussed in the 2009 Asset Condition Report

D. Asset Condition Strategies and Programs

There are increases in forecast spend in this category related to re-categorization of "Other" in the 2009 report and identification of particular sub-transmission asset condition projects, as noted in the 2009 Asset Condition Report.

Table III-9
Variance Summary ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	30,218,000	8,929,000	8,753,000	6,915,000	6,865,000	-	31,462,000
2010 CIP	-	25,032,000	30,070,000	25,034,000	32,496,000	38,812,000	151,444,000

Sub-Transmission Line

This program covers the proactive refurbishment and/or replacement of sub-transmission overhead lines and their associated assets to ensure the sub transmission system continues to perform in a safe and reliable manner for the foreseeable future. As noted in the 2009 Asset Condition Report, replacement/refurbishment candidates are identified through Inspection, foot patrols, engineering reviews and the helicopter survey. The program is a multi year initiative to address issues across all divisions; it incorporates elements of the previous Wood Pole Strategy.

Drivers

The main driver for this program is to maintain reliability of the electric network based on condition assessment. Over the last ten years, sub-transmission has, on average, contributed just over one percent to the number of interruptions, but 15 to 17 percent of SAIDI, SAIFI.

Physical condition of the sub-transmission system has been assessed through local inspections, maintenance and helicopter surveys supported by local engineering reviews and 'walk downs'. The 2009 Asset Condition Report identified:

- 20 circuits for attention based on Inspection and Encroachment reports
- 7 percent of assets reviewed by the Inspection and Maintenance program in 2009 requiring response (I&M reviews 20 percent of the system each year); 20 were in a state which required immediate action
- 15 lines with significant deterioration of foundations, requiring work to ensure structural integrity
- 25 lines requiring refurbishment or relocation
- 24 lines requiring pole replacements, reconductoring and other rebuilds

Poor or deteriorated condition of some steel tower foundations are also giving rise to concerns of the integrity of the tower to withstand the mechanical stresses imposed on it particularly during times of high wind or ice loading.

More detailed justification for this program is given in Exhibit 32.

Customer Benefits

Refurbishment and replacement of sub-transmission system components have a significant impact on SAIDI/SAIFI and Customer Minutes Interrupted (CMI). An annual impact of 0.15 SAIFI and 20.3 minutes SAIDI are significant elements of system reliability statistics.

2009 to 2010 Variance Explanation

There was no single 2009 Report element which maps directly to the present program. Sub-transmission Line includes elements of Wood Poles and Circuit Hardening and a re-categorization of "Other" from the 2009 report.

Table III-10
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	4,079,000	-	-	-	-	-	4,079,000
2010 CIP	-	16,036,000	18,065,000	9,700,000	-	-	43,801,000

Major Program Elements

The 2009 Asset Condition Report identified work for 2010/2011 onwards. The following table identifies individual projects within this program which equal or exceed $2,000,000 total forecast spend – noting that these are pre-engineering estimates.

Table III-11
Program Elements ($)

Project name	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Rathbun-Labrador #39 Rebuild	1,000,000	1,000,000	-	-	-	2,000,000
Lake Clear-Tupper Lake #38 Rebuild	1,000,000	2,000,000	1,000,000	-	-	4,000,000
Gloversville - Canaj. #6 Refurbish	-	1,000,000	1,000,000	-	-	2,000,000
Batavia-Attica 206-34.5kv	2,500,000	500,000	-	-	-	3,000,000
N Leroy - Attica 208 Refurbishment	1,100,000	1,000,000	-	-	-	2,100,000
Battenkill-Cambridge 2/5 Refurbish	1,100,000	1,000,000	-	-	-	2,100,000
Amsterdam-Rotterdam 3/4 Relocation	-	250,000	2,000,000	-	-	2,250,000

Sub-Transmission Underground Cable

As noted in the 2009 Asset Condition Report, there are approximately 1,100 miles of sub-transmission underground cable that includes many older and many poor condition cables. Approximately one-half is more than 47 years old and one-third is more than 60 years old. The distribution and sub-transmission underground cable asset replacement program replaces cables that are in poor condition, have had a history of failure or of a type known to be likely to have performance issues, as noted in the 2009 Asset Condition Report. Currently the distribution and sub-transmission programs are separate but a common program is currently being devised which will apply new technologies and address replacements proactively, prioritized by condition and risk. A revised program is being developed to address all underground cables as they face common failure modes, have similar deterioration mechanisms and require similar test and assessment techniques.

Drivers

Sub-transmission cables do not usually impact reliability as the system is heavily networked. There are, however, significant repair activities described in the 2009 Asset Condition report as exemplified by the Buffalo cable repairs 2005-2008.

Table III-12
Buffalo Cable Repairs

	2005	2006	2007	2008
Number of repairs	80	38	43	63

In addition, particular cable types (lead, XLPE) show deterioration which is greater than for similar cables of the same vintage.

Over the 10 year period beginning in 1999, underground cables were the third highest contributor to deteriorated equipment SAID/SAIFI, with individual annual average contributions of 0.016 SAIFI and 2.16 minutes SAIDI.

Further justification for this program is given in Exhibit 33.

Customer Benefits

Through a more proactive approach to cable condition analysis and preventative work, a program may reduce the impact of failures by 50 percent over 5 years

2009 to 2010 Variance Explanation

The 2009 program was based on a blanket approach to repairs and assessment. The proactive approach for future years better reflects the condition and operational history of cables.

Table III-13
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	4,079,000	-	-	-	-	-	-
2010 CIP	-	3,500,000	6,674,000	7,838,000	11,615,000	12,693,000	42,320,000

The sub-transmission underground cable replacements are being identified and planned based on condition, but there is a significant element based on System capacity and Performance. Present strategies which address sub-transmission cable[47] will be unified in the coming financial year.

There is significant variability in the planning of a cable replacement project based on local permitting and street access. These influences are taken into account and reflect a planning element of the budget in future years.

Major Program Elements

As noted in the 2009 CIP, each sub-transmission area is evaluated as a whole system and the best system design is determined before any one-for-one cable replacement program is implemented. Examples of sub-transmission cables currently being reviewed are McBride – Brighton #20 and #22 in the Central Division, Partridge-Avenue A #5 and Riverside to South Mall in the Eastern Division, and Elm St, Seneca, and Kensington 23kV Underground Circuits in the Western Division

Sub-Transmission and Distribution Steel Tower

This program covers both towers and their foundations for identification and repair of issues relating to steel members and the concrete supports. As noted in the 2009 Asset Condition Report, there are approximately 3,800 steel towers on the sub-transmission system, the majority of which are 60-90 years old.

[47] Primary Underground Cable Strategy & Sub-transmission Underground Cable Strategy

Drivers

Corrosion is the natural life limiting failure mechanism for towers. The end of life of a tower is recognized as the point at which sufficient numbers of steel members require replacement or welding repair that it is more economic to replace the whole tower. Alternatively the end of useful life may be a point at which it is no longer safe to work on the tower.

For those towers in the poorest condition there is a higher risk of storm damage and possibly safety related issues as demonstrated by the cascade failure of 15 double circuit towers on the 12 kV system adjacent to Packard Road in Niagara Falls at the beginning of November 2009.

Further information for this program is provided in Exhibit 34.

Customer Benefits

In late 2009 a number of steel towers on the Packard-Harper Line collapsed as a result of a single tower failure causing a cascade effect. Prevention of further such incidents is one of the key drivers for this program. Contributions of sub-transmission deteriorated cross-arms to system reliability statistics are SAIDI of 3.0 minutes and SAIFI of 0.017. At present foundations are not recorded as separate causes of incidents.

2009 to 2010 Variance Explanation

There was no single element of the 2009 CIP Report which covered steel towers and their foundations. There is an effort to align this program with the "I&M" program. It is noted that due to the specific nature of steel towers and their foundations that a separate line item for these items will be required.

Table III-14
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	**-**	-	-	-	-	-	-
2010 CIP	-	750,000	2,250,000	3,750,000	5,250,000	5,250,000	17,250,000

Major Program Elements

Divisional initiatives reflecting accelerated investment in tower refurbishment are a result of on-going tower inspection.

Table III-15
Program Elements ($)

Project name	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
IE - NE SubT Towers	250,000	750,000	1,250,000	1,750,000	1,750,000	5,750,000
IE - NC SubT Towers	250,000	750,000	1,250,000	1,750,000	1,750,000	5,750,000
IE - NW SubT Towers	250,000	750,000	1,250,000	1,750,000	1,750,000	5,750,000

Wood Pole Strategy

As noted in the 2009 CIP[48] the Wood Pole Strategy covered both sub-transmission and distribution with the "I&M" program used to identify poles requiring replacement based on condition[49]. The separate capital program dedicated to wood poles will be phased out and wood pole issues addressed in other programs.

Wood poles were discussed separately in 2009's report – which noted that wood poles are covered through "I&M" program and Feeder Hardening, unless considered a part of a major rebuild. With the completion of the Feeder Hardening program in 2011, the replacement of wood poles will be a condition based approach through the "I&M" program.

2009 to 2010 Variance Explanation

The specific wood pole projects from the 2009 CIP will be incorporated into the "I&M" program. This re-categorization accounts for the variance between the 2009 CIP and this year's filing. The budget forecast for FY11 and FY12 relate to two ongoing projects with extensive pole and switch equipment installation.

Table III-16
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	9,063,000	1,100,000	850,000	350,000	-	-	2,300,000
2010 CIP	-	150,000	250,000	-	-	-	400,000

Sub-Transmission Circuit Hardening

This program focused on reliability performance improvement and is no longer required as the "I&M" program replaces it. Causes of unreliability will be addressed through a combination of the "I&M" program and targeted activities based on reliability and available condition data. This includes insulator failure analysis and replacements

2009 to 2010 Variance Explanation

Circuit hardening will be incorporated into the "I&M" program. This program addressed specific arrester failure issues, as identified in the 2008 and 2009 Asset Condition Reports. Future activity related to this program will be addressed through the Sub-Transmission Overarching Strategy.

48 Transmission and Distribution Capital Investment Plan, Case 06-M-0878, January 30, 2009, pg. III-3
49 I&M reference

Table III-17
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,068,000	-	-	-	-	-	-
2010 CIP	-	-	-	-	-	-	-

Sub-Transmission Substations and Associated Assets

Sub-transmission substation asset strategies have been developed hand in hand with those for similar equipment in distribution and therefore include analysis of sub-transmission substation equipment.

The following substation sections detail the major strategy areas where The Company is targeting to spend in excess of $1 million dollars in any one financial year on sub-transmission substation equipment.

Sub-Transmission Indoor Substations

The Company identified 22 indoor substations located in Buffalo and six indoor substations located in Niagara Falls with asset condition issues, as described in the 2009 Asset Condition report. The Buffalo indoor substations that were built in the 1920s through the 1940s are targeted for replacement or refurbishment.

Drivers:

Key drivers for the station rebuilds are safety issues due to the poor condition of the assets discussed in the Company's Asset Condition reports for 2008 and 2009.[50,51] Some issues are described below:

- The 23 kV Condit oil switches do not have the capacity for the fault conditions and have led to injury.
- The 4.16 kV oil circuit breakers requires the operator to be standing at the breaker, they have no provision for proper safety grounding for maintenance.
- The protective relay scheme is of obsolete design, and does not provide adequate protection for some types of faults.
- The primary relays have inappropriate blocking which may lead to extensive damage of primary equipment
- Inadequate transformer bank rating and ventilation
- The transformer loading at some stations appears to be at or above 100 percent, based on historical allocated capacity values.
- Poor ventilation in transformer bays has led to transformer overheating and possible accelerated aging of insulation as transformer loads have increased.

[50]Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2008, p 53.
[51] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pgs. III-122 through III-123.

- Since control, protection, cabling, circuit breakers, and structures are obsolete, a failure of a single component in the substation may not be easily addressed. This situation could cause an extended outage and in many cases the component will have to be replaced.

Customer Benefits:

This strategy will address safety concerns associated with these indoor substations.

This work is expected to reduce the SAIDI. This improvement is based on a reduction in the mis-operations with the addition of automation for control and monitoring but is unlikely to be quantifiable.

2009 and 2010 Variance Explanation:

As the Indoor Substation program has developed, better identification of the sub-transmission elements has been performed and capital forecast for subsequent years. This is in line with the Distribution elements of the same stations. The increased forecast has resulted in a recategorization of “Other” from the 2009 plan.

Table III-18
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,000,000	125,000	125,000	-	-	-	250,000
2010 CIP	-	659,000	1,925,000	1,800,000	1,800,000	1,800,000	7,984,000

Major Program Elements

As noted in the 2009 Asset Condition Report, Buffalo Station 29, 23, 43, and 52 are currently being rebuilt with completion scheduled at the end of FY11. Buffalo Stations 27, 37, 59, and 25 are scheduled for FY12-13.

Sub-Transmission Metalclad Switchgear

This strategy replaces metal clad switchgear installed prior to 1970 beginning with those metalclads that have sustained a failure or are of a manufacturer type where a failure has occurred.[52] As noted in the asset condition report,, there are approximately 220 metalclads in service in NY operating at 13.2kV, 4.16kV and 4.8kV. Of these approximately 70 were installed in the 1960’s and 1970’s. This program includes the replacement of two metalclad substations per year using age and manufacturer as a support to condition assessments being performed using electro-acoustic methods.

[52] Details on this strategy are included as Exhibit 34 in “Transmission and Distribution Capital Investment Plan,” October 22, 2007.

Drivers

Several design factors with older vintage metalclad substations contribute to bus failures or component failures. These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the failures of metal-clad switch-gear, substations and busses. Gaskets and caulking of enclosures deteriorate over time allowing rain and melting snow to enter.

- Ventilation - Metalclad interiors can reach high temperatures in the summer even if ventilation systems are working correctly. High temperatures degrade the lubrication in breaker mechanisms and other moving parts, and can cause failure of electronic controls and relays

- Insulation - Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages are apparent in earlier vintage switchgear.

Further information for this program is provided in Exhibit 35.

Customer Benefits:

Though occasional, each metal clad event contributes an average SAIDI value of 0.35 minutes and a SAIFI of 0.002. The impact on local customers is usually more substantial, with almost 3000 customers interrupted for over three hours. Offsetting this interruption is of significant benefit to the customers concerned.

2009 and 2010 Variance Explanation

Individual metalclad installations, as identified in the 2009 Asset Condition Report have been identified and condition assessed. Individual projects are under way and the capital forecast reflects the increased knowledge of asset condition. Further individual installations will be added to the program based on prioritized risk assessment.

Table III-19
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 –FY14/15
2009 CIP	1,500,000						-
2010 CIP		1,250,000	1,900,000	-	-	-	3,150,000

Major Program Elements

Individual stations are targeted for metal clad replacement based on the strategy and condition review. The following stations are in progress, with a statewide program available to prioritize further stations.

Table III-20
Program Elements

Project	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 –FY14/15
Replace/Relocate 13.8kV SG @Oneida	300,000	1,900,000	-	-	-	2,200,000
North Troy Metal Clad Repl.	950,000		-	-	-	950,000

Sub-Transmission Circuit Breakers and Reclosers

As noted in the Asset Condition Report, The Company has 4,106 circuit breakers (4,053 operating and 53 spares) on the distribution system, with an average age of 33 years.[53] Older obsolescent units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. The current strategy for substation circuit breakers and reclosers is based upon a mixture of maintenance, refurbishment and replacement of those assets that are less safe or less reliable due to poor condition, obsolescence or availability of spares.[54]

Drivers:

The current strategy for substation circuit breakers and reclosers is based upon a mixture of maintenance, refurbishment and replacement of those assets that are less safe or less reliable due to poor condition, obsolescence or availability of spares.[55] The Company has 4,106 circuit breakers (4,053 operating and 53 spares) on the distribution system, with an average age of 33 years.[56] Aged units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. Likewise, unreliable units have been identified for replacement because their replacement would reduce the number of customer interruptions.

Further information for this program is provided in Exhibit 36.

Customer Benefits:

Several of the targeted breaker families present opportunities to reduce potential hazards associated with safety and the environment (i.e., oil and asbestos). This strategy will help improve reliability by proactively replacing or refurbishing units with poor reliability or mitigate the risk of future unreliability. Breaker failures have resulted in an average of 20

[53] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pg. III-131.
[54] Details on this strategy are included as Exhibit 27 in "Transmission and Distribution Capital Investment Plan," October 22, 2007.
[55] Details on this strategy are included as Exhibit 27 in "Transmission and Distribution Capital Investment Plan," October 22, 2007.
[56] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pg. III-131.

substation events per year in the last five years (as reported in SIR) with an average of 12,000 customers interrupted and 1.5 million customer minutes interrupted. This equates to a SAIFI of 0.007, a SAIDI of 0.96 and a CAIDI of 130.6 minutes.

Noting that:

- "Deteriorated equipment" (reported in the SIR data) makes up ~50 percent of the reliability contribution for breakers
- Not all "deteriorated" breakers will be in the program – other units than those in the program will also will degrade
- The program covers a five year period to address specific families of breakers
- There is significant year-on-year variability in breaker contributions to reliability statistics

An improvement in the upper limit of 10 percent of current SAIDI/SAIFI related to circuit breakers may be identified: SAIDI ~0.1 and SAIFI ~0.001

2009 and 2010 Variance Explanation

This program was not fully developed and was delayed to future years. It is being developed to replace targeted breakers in a multi year manner.

Table III-21
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,645,000	-	-	-	-	-	-
2010 CIP	-	-	300,000	2,640,000	2,800,000	3,019,000	8,759,000

Major Program Elements

The program is set up for breaker replacement by division; the strategy identifies individual breakers for replacement. Field teams in conjunction with subject matter experts coordinate which breakers to address in which year.

IV. DISTRIBUTION SYSTEM

This chapter describes the capital investment projects and strategies that The Company is pursuing on its distribution facilities. The current five year plan is represented in Table IV-1.

Table IV-1
Distribution Capital Expenditure by Spending Category

Spending Category	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Damage/Failure	20,934,000	22,104,000	22,916,000	23,717,000	24,633,000	114,304,000
Statutory/Regulatory	121,588,000	141,754,000	144,586,000	144,765,000	150,066,000	702,759,000
System Capacity & Performance	65,090,500	50,263,000	52,784,000	59,577,000	59,103,000	286,817,500
Asset Condition	33,141,000	35,485,000	39,130,000	41,165,000	46,220,000	195,141,000
Non-Infrastructure[57]	3,246,500	5,394,000	5,584,000	5,776,000	5,978,000	25,978,500
Total	244,000,000	255,000,000	265,000,000	275,000,000	286,000,000	1,325,000,000

Details of the strategies and the projects included in the plan are provided in Exhibits 37 and 38 and described in the following sections.

The following are some accomplishments for The Company's distribution system in 2009.

- Approximately 4,300 poles replaced
- Over 650 line transformer replacements
- More than 1030 miles of feeder hardening completed;
- Approximately 190 reclosers installed
- Approximately 7,600 miles of Distribution Line inspected
- Replaced 12,405 potted porcelain cutouts
- Approximately 4,200 substation inspections
- Buffalo Stations 23, 29, 43 and 52 are under construction and 40 percent complete.
- Cycle trimming completed on over 5,100 miles

[57] Non-Infrastructure largely contains General Equipment and Telecommunications blankets. The General Equipment projects are for field equipment, tools or specific equipment requirements which have costs are greater than $200/per unit. They allow for purchase of non-infrastructure equipment involved in support of operations. While most of this balance is included in blanket projects, a reserve has also been set up to budget for specific projects which walk-in during the year for purchases of equipment known to cost more than $100k. These reserves are based on historical walk-in calculations for specific projects within the category. Telecommunications projects collect costs associated with works to support operations and facilities telecommunications requirements during the year. This includes the installed cost of telephone and wireless equipment for general use in connection with distribution electric utility operations. This includes radios and radio towers, antennae, etc.

A. Statutory/Regulatory Strategies and Programs

Capital spend in this category are required to ensure that the facilities meet the minimum legal, regulatory and contractual obligations of the Company. Statutory/Regulatory work is not handled under a specific strategy. Work in this category includes new business, public requirements, outdoor lighting, and transformer and meter purchases. The projected investment is shown in the table below. As additional projects are identified through external requests funds will be allocated as appropriate.

Table IV-2
Statutory/Regulatory Spending Categories

	Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
Blankets	2009	**79,167,000**	85,157,000	87,714,000	90,345,000	93,058,000	-	356,274,000
	2010		88,958,000	96,294,000	102,501,000	107,848,000	114,432,000	510,033,000
Statutory/ Regulatory Specifics	2009	6,729,000	4,094,000	-	-	-	-	4,094,000
	2010		15,190,000	16,500,000	17,010,000	14,860,000	15,590,000	79,150,000
Inspection & Maintenance	2009							
	2010		17,440,000	28,960,000	25,075,000	22,057,000	20,044,000	113,576,000
Total	2009	85,896,000	89,251,000	87,714,000	90,345,000	93,058,000		360,368,000
	2010		121,588,000	141,754,000	144,586,000	144,765,000	150,066,000	702,759,000

Most of the statutory/regulatory expenditures are accounted for via blanket projects. Individual work orders are written and approved to cover expenditures that are part of the company's franchise, tariff, regulatory, or governmental requirements. The scope and timing of this work is, for the most part, dictated by others. The blanket category spending estimates are established by a review of the historical and forecasted spending. These estimates reflect consideration given to inflation, estimates of materials, labor, and indirect cost, market sector analysis, overall economic conditions and historical activity.

The statutory/regulatory blankets include items such as New Business Residential, New Business Commercial, Outdoor Lighting, Public Requirements, Transformer Purchase and Installation, Meter Purchase and Installation, Third Party Attachments, Land Rights, and Damage Failure and Distribution Substation. Exhibit 38 shows the detailed spending for all blankets in this category. Five of the blankets account for approximately 90 percent of the spend in FY10/11, and are detailed below:

- Transformer Purchase
  - Purchase only transformer blanket: Transformers are purchased from outside vendors and are shipped to locations within the company where these items are put into stores. Transformers are capitalized upon purchase.
- New Business Residential

- Installation of new overhead or underground services to residential customers, new connections and reconnections as well as miscellaneous equipment related to the services;
- Extension of the primary voltage system directly related to providing service to a new residential customer or development;

- New Business Commercial
- Installation of new services to commercial customers, new connections and reconnections as well as miscellaneous equipment related to the services.
  - Extension of the primary voltage system directly related to providing service to anew commercial customer or development
- Public Requirements
  - This project covers overhead and underground facilities construction and relocations resulting from bridge or roadway rebuilds, expansions, or relocations;
  - Municipality requests to relocate overhead facilities underground;
  - Other public authorities requesting or performing work that requires equipment or facilities to be relocated due to this work;
- Public Outdoor Lighting
  - Installation and removal of street lighting or flood lighting and related equipment.

Inspection and Maintenance Program

The Company will inspect all electric line assets (Distribution Overhead, Underground, and Sub-transmission line assets) once every five years under this program. Each inspection will identify and categorize all necessary repairs (or asset replacement) against a standard and in terms criticality to improve the reliability of the network for customers.

There are three types of inspections conducted by the Company:

- Visual inspections of overhead, underground, and sub-transmission line
- Aerial assessments of sub-transmission lines
- Infrared inspections of overhead distribution mainline sections of the feeders and overhead terminations on underground facilities

This program will replace some of the existing strategies program work such as feeder hardening, potted porcelain cutouts, targeted pole replacements, miscellaneous overhead, miscellaneous underground, manholes, and vaults.

The Company will also perform annual elevated voltage testing per Order 04-M-0159 amended and effective December 15, 2008 on all facilities that are capable of conducting electricity and are publicly accessible, such as street lights.

It is important to note that this program incorporates elements of the 2009 CIP report which were identified separately. These 2009 programs include “Wood Poles”, “Miscellaneous Overhead Equipment”, and “Miscellaneous Underground Equipment”.[58]

Drivers:

The 2009 Asset Condition Report details application of the Inspection and Maintenance program to both distribution and sub-transmission line assets.[59] The purpose of the program is to:

- Improve the reliability of the electric distribution network based on a condition assessment
- Improve the safety of customers and employees by identifying and addressing locations with elevated voltage
- Improve the efficiency of T&D service by optimizing the timing of maintenance activities and asset replacements
- Meet the mandated requirements set forth by the PSC and provide for a sustainable distribution and sub-transmission system

Further information for this program was provided as Exhibit 31.

Customer Benefits

The Inspection and Maintenance Program is designed identify and eliminate elevated voltage levels on the Company’s facilities that are capable of conducting electricity and publicly accessible.

2009 to 2010 Variance Explanation

The inspection and maintenance program is replacing the prior programs of feeder hardening, targeted pole replacement, and overhead miscellaneous capital. The phase in of budgeting for I&M program in place of prior programs is expected in FY10/11 Funding for I&M was previously budgeted in the Asset Condition spending rationale.

Table IV-3
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	N/A	-	-	-	-	-	-
2010 CIP	N/A	17,440,000	28,960,000	25,075,000	22,057,000	20,044,000	113,576,000

58 Throughout this chapter, the Company notes programs that are now integrated into the Inspection and Maintenance program.
59 Ibid, pgs. III-78 and III-95

Major Program Elements

The major elements are line work and underground cable work. Work is performed based on inspection results of the 20 percent of the system inspected each year.

B. Damage/Failure Strategies and Programs

Damage/Failure category projects are those capital expenditures required to replace failed or damaged equipment and to restore the system to its original configuration and capability as a result of damage or equipment failure on an as-needed basis. Damage/Failure work is not handled under a specific strategy or program; rather the work is initiated as failures occur. The spending basis represents a historical level of funding for damage to equipment or failures caused by storms, vehicle accidents, vandalism or deterioration. This category contains an allocation to address failures which arise throughout the year. Most damage failure occurrences are single structures events and are handled under blanket projects. Blanket projects are used to capture individual, small value, relatively high volume work orders that are of standard construction and scope, short duration, and limited to a maximum of $100,000 per work order.

Damage/Failure projects can be specific projects if over $100,000, or handled under blanket projects. The blanket category spending estimates are established by a review of the historical and forecasted spending. These estimates reflect consideration given to inflation, estimates of materials, labor, and indirect cost, market sector analysis, overall economic conditions and historical activity.

2009 to 2010 Variance Explanation

In the 2009 CIP Storm Related projects appeared in System Capacity & Performance but have now been recategorized as Damage/Failure. Further improvements in budget forecasting have been produced via commodity pricing analysis.

Table IV-4
Damage/Failure Variance

	Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
Blankets	2009	17,128,000	18,868,000	19,434,000	20,017,000	20,617,000	-	78,936,000
	2010		15,815,000	16,724,000	17,343,000	17,950,000	18,650,000	86,482,000
Allocation for Specific Projects	2009	1,073,000	1,100,000	-	-	-	-	1,100,000
	2010		5,119,000	5,380,000	5,573,000	5,767,000	5,983,000	27,822,000
Total	2009	18,201,000	19,968,000	19,434,000	20,017,000	20,617,000		80,036,000
	2010		20,934,000	22,104,000	22,916,000	23,717,000	24,633,000	114,304,000

C. System Capacity and Performance Strategies and Programs

System capacity and performance strategies and programs are designed to address loading and reliability issues. Strategies and programs in this category primarily include capacity planning, recloser installations and engineering reliability reviews. Capacity planning and engineering reliability reviews currently are not documented by strategies, but have established methods, practices and plans in place. A planning strategy is currently under development. The recloser application program is covered by a fully developed strategy and discussed in this section.

Capacity Planning

An annual review of distribution substation and feeder loading known as the “Annual Plan” is performed to review equipment utilization. Forecasted load additions are applied to historical data and the system is proactively analyzed to determine where and when constraints are expected to develop. Recommendations for system reconfiguration or system infrastructure development are created as part of this annual review to ensure load can be served during peak demand periods. The scope of the Annual Plan includes the entire distribution system. The ongoing development of this annual process has already allowed us to realize improved consistency in areas such as the application of planning guidelines, load forecasting, equipment ratings, project estimating, analysis techniques, development of project scopes, and project prioritization.

The 2009 Annual Plan focused on the identification of load relief plans for all facilities that were projected to exceed 100 percent of normal (i.e., maximum peak loading allowed assuming no system contingencies) capability. The projects from these reviews are intended to be scheduled to be in service during the year the load limit is forecasted to occur. Other potential capacity work has been identified and included in future years of the capital investment plans. The need and timing of these projects will be reviewed in subsequent annual capacity planning efforts have been made for any project for which construction needs to begin in FY09/10. In addition to the normal loading review, certain locations with significant load (greater than 20MWs peak) exposed to long duration (greater than 24 hours) outages for single contingencies on the supply system were also analyzed. Load growth within the service area has averaged a modest 1 percent over the past 10 years and that modest growth rate is expected to continue at a similar level for the next 10 years. There are, however, areas within the distribution system that are forecasted to grow at higher rates. Therefore, load forecasts for individual feeders and substations that ranged from 0.5 percent to 6.8 percent annually were developed.

The 2009 Annual Plan reviewed loading on over 2000 feeders and approximately 600 substations. The review identified 123 feeders and 63 power supply transformers that were projected to exceed 100 percent of summer normal capability during peak load periods in 2009. Action plans to address these issues were included in the capital plan via both the Load Relief blanket projects as well as individually specified funding projects for the larger projects.

Forecasted spending amounts in the capital plan are provided in Table IV-5. As additional projects are identified through the annual review process and ongoing work, funds will be allocated to the later years as appropriate.

A Planning Strategy is expected to be published prior to the end of the current fiscal year. This strategy will provide consistent guidance on normal loading practices and expected system contingency response capabilities for distribution facilities. In addition, a more granular load forecasting methodology is under active review to better forecast the variance in growth within individual study areas.

In addition to the planning strategy, continued development of system analysis tools and models is necessary. The “green economy” energy efficiency programs or distributed generation, plug in electric vehicles, and any “Smart Grid” technologies can have an impact.

2009 to 2010 Variance Explanation

The 2010 CIP includes a number of major developments related to substation projects, including Sycaway, Swann Road, East Golah and Inman Station.

Table IV-5
Program Variance ($)

	Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
Planning Specific Projects	2009	37,819,000	12,210,000	2,080,000	30,000	30,000	-	14,350,000
	2010		28,777,000	20,356,000	21,348,000	20,179,000	23,205,000	113,865,500
Load Relief Blankets	2009	2,531,000	2,787,000	2,871,000	2,957,000	3,046,000	-	11,661,000
	2010		1,104,000	1,144,000	1,193,000	1,233,000	1,288,000	5,962,000
Total	2009	40,350,000	14,997,000	4,951,000	2,987,000	3,076,000		26,011,000
	2010		29,881,000	21,500,500	22,541,000	21,412,000	24,493,000	119,827,500

Distribution Line Transformer

The Distribution line transformer strategy involves a “forward looking” approach to mitigating outage/failure risks due to overloading and asset condition. Transformer loading is reviewed annually via reports generated from the transformer loading information within the Geographical Information System (GIS). Transformers with calculated demands exceeding load limits specified in the applicable Construction Standard are investigated and any overloaded installations addressed.

The physical condition of distribution line transformers is evaluated on a five-year cycle as part of the Overhead and Underground Inspection and Maintenance Programs. Poor condition units are being replaced based on inspection results.

Heavily loaded units are to be systematically removed from the system over the next fifteen years. Unit replacements will increase year-on-year for the first five years of the program and stabilize for the remaining 10 years. Replacement levels may be adjusted based on changes to loading levels, the condition of the population and budget constraints.

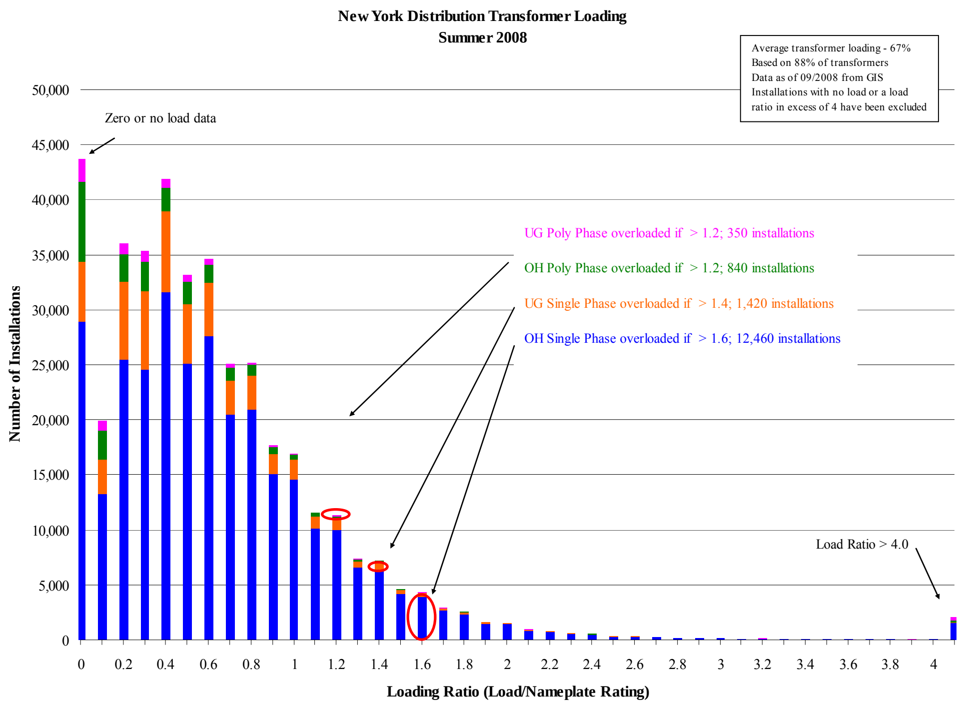
Drivers

As discussed in the 2009 Asset Condition Report, there are approximately 446,600 overhead and padmount distribution transformers. As discussed in the 2009 Asset Condition Report, the average age of overhead units is 22 years with three percent older than 50 years and less than one percent older than 60 years. The average age of the padmount units is 16 years with less than one percent older than 50 years. The average size of overhead units is 27 kVA, for padmount units the average size is 107 kVA. Between December 1, 2008 and August 10, 2009 inspections were completed on approximately 57,000 overhead and 9,900 padmounted transformers, which represent approximately 15 percent of the population. The 2009 Asset Condition Report noted a number of issues associated with transformer inspection results such as cracked or broken bushings, weeping oil, and other related problems.[60] Condition-based replacements will be managed through the Inspection and Maintenance Program.

Heavily-loaded transformers do not currently represent an increasing problem. Proactive management of equipment loading through annual review will maintain this situation (Figure IV-1)

[60] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pg. III-103.

Figure IV-1
Distribution Line Transformer Loading



There are approximately 250 transformer failures per year due to overloading, which affects approximately 3,700 customers annually. Further information for this program is provided in Exhibit 39.

Customer Benefits:

The main benefit of this strategy is that asset utilization will be maximized by maintaining units in service until such point that replacement is required as identified through recurring loading reviews or visual and operational inspection, recognizing that transformer life expectancy is predominantly affected by loading and environmental factors rather than age. Implementation of this Strategy will ensure the sustainability of this asset class over time and maintain its relatively minor impact on overall system reliability and customer satisfaction.

2009 to 2010 Variance Explanation

The vast majority of Distribution Line Transformer work is addressed through System Capacity and Performance, with a small element remaining from Asset Condition.

Table IV-6
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,151,000	1,989,000	2,085,000	2,184,000	2,286,000	-	8,544,000
2010 CIP Asset Condition		125,000	-	-	-	-	125,000
2010 CIP Sys Cap		4,500,000	4,602,000	7,599,000	9,651,000	5,460,000	31,812,000

Feeder Hardening

The intent of this Strategy is to identify feeders with characteristics indicating the potential for significant reliability performance improvements related to animals, overhead deteriorated equipment and/or lightning interruptions. This is a reliability-focused strategy designed to meet state regulatory targets.

This program is funded for the final year of its five years in FY11 as the “I&M” program then addresses asset condition issues.

After identification and local review, the feeders become part of the Feeder Hardening Program. Feeders in this program are surveyed for deteriorated equipment and non-standard grounding/bonding.

Drivers:

The main driver of the Feeder Hardening Strategy is asset condition.[61] Deteriorated equipment, lightning and animal related outages were steadily increasing prior to the program being implemented in FY2007, thus impacting reliability.

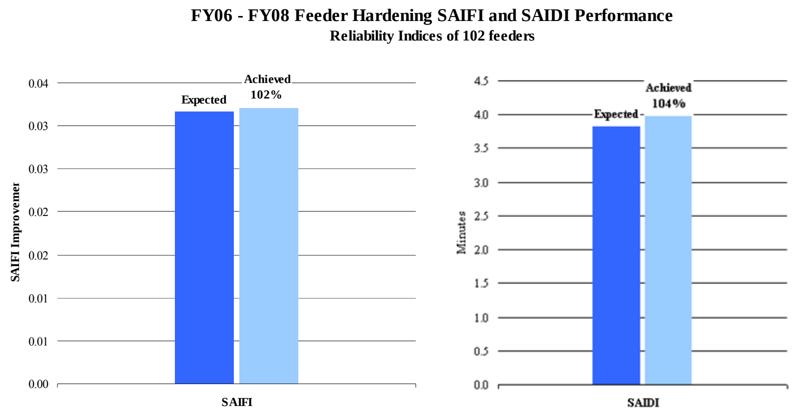
Customer Benefits

Through October of 2009, approximately 200 feeders have been completed representing more than 6,000 circuit miles of feeder hardening. This work is expected to reduce the five-year average SAIDI by 8 minutes on an IEEE basis by FY 2011. This improvement is based on a reduction in the number and magnitude of deteriorated equipment, lightning and animal related interruptions in upgraded sections. FY11 is the last year of the five-year program.

The actual performance improvement on the 102 feeders previously completed through the end of FY2008 is shown in the figure below.[62]

[61] Report on the Condition of Physical Elements of Transmission and Distribution Systems, 06-M-0878, October 1, 2009, pgs. III-116-III-117.
[62] Report on the Condition of Physical Elements of Transmission and Distribution Systems, 06-M-0878, October 1, 2009, pg. III-116.

Figure IV-2
Feeder Hardening Reliability Performance



Further information for this program is provided in Exhibit 40.

2009 to 2010 Variance Explanation

The feeder hardening program will end in FY11 to be replaced by the Inspection and Maintenance Program.

Table IV-7
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	6,591,000	8,265,000	8,265,000	5,265,000	5,265,000	-	27,060,000
2010 CIP	-	3,000,000	-	-	-	-	3,000,000

Major Program Elements

This is a programmatic approach to reliability improvement which does not have specific large capital elements.

Pockets of Poor Performance

The intent of this strategy is address poor system performance for the small numbers of customers who see a relatively high number of interruptions. This program will be funded for the first time in fiscal year 2011.

- Some customers experience a number of interruptions that are significantly above the system average (i.e. SAIFI). This number of customers is small and addressing their situation only minimally impacts overall system statistics (i.e., SAIDI, SAIFI and CAIDI). However, the customers are aware of interruptions and the local poor performance.
- Specifically, this program will address the following:

- Identification of 'pockets of poor performance' which are subsections of feeders (typically at the line fuse level) experiencing measurably more frequent interruptions than the remainder of the feeder through statistical performance analysis
- Local reliability and operational review to determine the source of the performance pocket and opportunities for improvement
- Plans and executes improvements for identified pockets
- Proactively identifying 'hot spots' through the same analysis to identify performance pockets which could become future pockets so that they may be addressed ahead of time.

Drivers

The company has identified 126 pockets of poor performance on 104 of the more than 1,900 feeders in New York. These areas are distributed across some specific areas in New York, as per the attached map. The performance issues in these pockets range from tree limbs to unknowns and are unlikely to be addressed through standard Inspection and Maintenance activities. The pockets have an average size of 85 customers, therefore, it is unlikely that any pocket will appear as SAIDI/SAIFI contributors.

Further information for this program is provided in Exhibit 41.

Customer Benefits

There is significant benefit to the customers served by the identified pockets.

2009 to 2010 Variance Explanation

This program is funded for the first time in FY11. The budget identified in FY10 was reallocated to higher priority programs.

Table IV-8
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	561,000	-	-	-	-	-	-
2010 CIP	-	2,130,000	2,130,000	2,130,000	2,130,000	2,130,000	10,650,000

Major Program Elements

No individual pocket is of significant size or likely capital impact.

Remote Terminal Units (RTU's)

This strategy covers the addition of Remote Terminal Units (RTU's) and related infrastructure at substations presently lacking remote management capabilities. RTU's in substations subsequently communicate to EMS (Energy Management Systems) and provide the means to leverage substation data that provides operational intelligence and significantly reduces response time to abnormal conditions through real time monitoring and control.

Currently over 150 out of the 441 distribution and sub-transmission substations in New York require installation of RTU's.

Drivers

RTU's will allow for remote operation and management of the system at these stations providing benefits in incident response and recovery and thus improving performance and reliability. In addition, RTU's are key components of automation and Smart Grid infrastructure. Further information is provided in Exhibit 42.

Customer Benefits

This strategy provides the means to leverage substation data that provides operational intelligence and significantly reduces response time to abnormal conditions through real time monitoring and control. The strategy also enables the distribution automation, sub-transmission automation, and future smart grid strategies. This will improve the service to customers. When used to monitor and control the distribution feeder breakers and associated feeder equipment, RTU's and EMS can provide up to a 15 percent to 20 percent reduction in average customer outage duration (CAIDI) when compared with a similar feeder that is not equipped with these facilities.

2009 and 2010 Variance Explanation

Remote Terminal Units were not identified as separate line items in the 2009 CIP report.

Table IV-9
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	2,500,000	3,000,000	3,000,000	4,000,000	4,000,000	16,500,000

Major Program Elements

Individual stations are identified based on a 2007/8 capital strategy paper analysis which identified stations where EMS would provide a benefit. Each station project is less than $1,000,000.

Distribution Line Recloser Application

This strategy provides line recloser guidelines to assist with the proper location and installation of reclosers on overhead distribution feeders.[63] The recloser application strategy is a reliability-focused strategy designed to support the company reliability performance through the installation of line reclosers on overhead distribution lines. Line reclosers are

[63] The current approved strategy was submitted in 2007 as part of the initial CIP filing as Exhibit 37.

needed to isolate permanent faults on the distribution system and minimize the scope of the interruption by protecting the feeder breaker. Ideally, reclosers are installed at locations which limit the size of the interruption to the fewest number of customers possible and/or reduce the mainline exposure on the feeder breaker. Reclosers should be installed at natural breakpoints in the distribution primary; bifurcations, long three phase taps, etc.

Line reclosers are primarily installed on 15 kV class distribution feeders with overhead exposure. This Strategy addresses installation of three phase reclosers. Single phase reclosers are currently being evaluated by The Company.

Drivers

The strategy is to install at least one recloser on every 15 kV class radial feeder with significant overhead three phase exposure (more than 10 miles) with a three year average distribution line SAIDI performance greater than 96 minutes. Additionally any circuit identified as a desirable candidate from the Recloser Model[64] would be eligible; the recloser model develops a $/Delta CMI for each location. Candidates will compete for inclusion in the budget based on their $/Delta CMI value, the more economic reclosers will be included.

Further information for this program is provided in Exhibit 43.

Customer Benefits

The overall system reliability benefits of the program will improve both outage durations and frequencies. The results of a recloser improvement model using generic assumptions identified approximately 250 potential locations with a potential reduction in SAIDI of 6.6 minutes and SAIFI of 0.037. Actual reliability improvements figures are determined based on the actual recloser locations and feeder configurations.

2009 to 2010 Variance Explanation

In the recent past the recloser program was expanded to advance reliability enhancements necessary to achieve regulatory performance targets. The Company plans to continue with an aggressive recloser program of approximately 100 new reclosers per year compared to the 169 that were planned for last year.

Table IV-10
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	7,482,000	8,400,000	8,820,000	9,261,000	9,723,000	-	36,204,000
2010 CIP	-	5,000,000	6,000,000	6,000,000	10,000,000	12,000,000	39,000,000

[64] As described in the Recloser Application Strategy: a means to identify locations where most benefits from reclosers would accrue.

Major Program Elements

No individual recloser application should exceed $100,000.

Engineering Reliability Reviews

A strategy for Engineering Reliability Reviews (ERR's) is under development, linking through to feeder performance and reliability. There is a documented review procedure, as noted in CIP 2009: the Distribution Asset Management Guideline 012 (DAM-012), which is summarized here.

The Network Asset Planning group is responsible for generating the list of Worst Performing Feeders is assembled during the preparation of the Electric Service Reliability Report and filed annually in accordance with Case 90-E-1119. The list of feeders includes outages associated with supply issues (transmission or substation) and excludes major storms. From the list, feeders are selected for an ERR. Each review includes:

- Review of historical reliability data. One year and three year for current issues and trends.
- Review of recently completed and/or future planned work which is expected to impact reliability.
- Review the need for the installation of radial and/or loop scheme reclosers.
- Review for additional line fuses to improve the sectionalization of the feeder.
- Comprehensive review of the coordination of protective devices to ensure proper operation.
- Review for equipment in poor condition.
- Review of heavily loaded equipment.
- Review for other feeder improvements such as fault indicators, feeder ties, capacitor banks, load balancing, additional switches to reconductoring (overhead and/or underground).

Budgeted spending on this strategy is provided in Table IV-11. The projects are a subset of the projects in the Reliability category not associated with a strategy.

Drivers

The Company has an obligation to report on the worst five percent performing circuits and provide recommendations to improve their reliability. The ERR's are the recommendations that are made to improve the reliability on the worst performing circuits. Further details can be found in Exhibit 44.

Customer Benefits

The ERR program will benefit the customer's reliability and regulatory communications by focusing our attention on the worst performing circuits. As these are circuits which are among the worst there will be a benefit to SAIDI and SAIFI and to those customers on the feeders.

2009 to 2010 Variance Explanation

The resolution in FY11 of on going ERR work and identification of new ERR work, based on the results of "Worst Performing Feeder" analysis accounts for the variation in budget. Future year forecasts are based on desktop calculations.

Table IV-11
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	3,220,000	4,233,000	4,206,000	4,167,000	4,377,000	-	16,983,000
2010 CIP	-	8,083,500	1,200,000	1,200,000	1,200,000	1,200,000	12,883,500

Major Program Elements

No individual program element is in excess of $1 million.

Distribution Automation

The distribution automation (DA) strategy is intended to improve the reliability performance of the distribution system by creating the capability for the system to "self heal" automatically faster than human intervention could accomplish. This will minimize customers permanently interrupted. To accomplish this, the distribution automation strategy encompasses the installation of DA as well as SCADA for reclosers, fault locators, and switches; the interface of DA enabled line devices with the substation feeder breaker; and communication by these devices back to central Operations Centers and database warehouses; and other related issues.

In addition to improving reliability performance, implementation of this strategy will increase the ease of operation and provide additional data for expansion or operational studies. The approved strategy contains the key points identified in the CIP2009, with equipment installed in the field as described in that report.

All relevant staff training has been completed and commissioning tests have been performed. The tests identified a latency issue with one device which has delayed the complete program roll out.

The DA pilot projects will be monitored for performance achievements to determine whether benefits and costs result in value to customers and are sustainable.

D. Asset Condition Strategies and Programs

Open Wire Primary

The intent of this Strategy is to replace all "small" (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations.

Drivers:

Approximately 4,800 circuit miles (14 percent) of the overhead circuit mileage falls into the category of small wire.

The small wire asset group consists mainly of older installations (greater than 50 years old); most conductors will have lost some tensile strength due to loading conditions and splicing activities, which make the conductor more likely to break during an interruption involving physical contact with the conductor (e.g. trees). This is especially significant during storm events due to additional wind/snow and ice loading. Additionally, small primary conductor contributes to increased voltage drop and line losses (especially in heavily loaded areas) due to the inherent higher impedance per unit length compared to larger conductors.

Approximately 4,800 circuit miles (14 percent) of the overhead circuit mileage falls into the category of small wire. The three-phase portion of the small wire circuit mileage is 510 miles (less than 2 percent of total, 11 percent of small wire). The majority of this small wire population is #6 and #4 copper/copperweld conductor.

Three general strategies have been developed to address this small wire population:

- Replace three phase installations on a feeder basis
- Replace both three phase and non-three phase small wire installations in areas identified as pockets of poor performance
- As part of all future overhead distribution projects

Three phase areas are the main focus due to the expected larger contribution to the overall performance of the feeder from a reliability, loss, voltage and loading perspective.

Small conductors have increased contributions to system losses, voltage drop and loading. Replacement of small primary will improve system performance in these areas.

Further information for this program is provided in Exhibit 45.

Customer Benefits:

The main benefit of this Strategy is that system performance will be improved by replacing "small" wire. Principle areas for this improvement are reliability, losses, voltage, and loading. Additionally this program will remove a group of assets from the system that are in poor condition based on inspection.

2009 to 2010 Variance Explanation

This program will be used to address two known locations of concern at Schuylerville 12 and Gilbert Mills 51, completing work already begun. As other locations are identified they will be addressed. Open Wire Primary replacement has not been identified for FY11/12 through FY13/14 due to its lower priority.

Table IV-12
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	3,413,000	2,400,000	2,400,000	150,000	150,000	-	5,100,000
2010 CIP	-	750,000	-	-	-	1,500,000	2,250,000

Major Program Elements

The following table provides the major project elements of the open wire program.

Table IV-13
Program Elements

Description	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
Schuylerville 12	200,000	-	-	-	-	200,000
Gilbert Mills 51	550,000	-	-	-	-	550,000

Manholes and Vaults

The intent of this program is to manage manholes and vaults on a condition based inspection. Manholes and vaults are inspected on a five year cycle and prioritized based on The Company's Electric Operating Procedures (EOP UG006-UG Inspection and Maintenance). The inspection priority system identifies and provides for timely condition-based replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle. Inspections are also made whenever work is done inside a manhole or vault.

Drivers

As discussed in the 2009 Asset Condition Report, there are approximately 16,800 manholes and 1,800 vaults across the system. Between December 1, 2008 and August 10, 2009, approximately 1,100 manholes and 72 vaults were inspected.[65] The typical mode of degradation is weakening of the roof structure. When these instances are identified, a civil engineer will evaluate each location, determine which locations are in need of repair or replacement and rank them in priority order. Further details are provided in Exhibit 46.

[65] Report on the Condition of Physical Elements of Transmission and Distribution Systems, October 1, 2009, p. III-114 and III-115

The inspection results are summarized in the table below.

Table IV-14
Manhole and Vault Inspection Results

Level	Missing Ground Rods	Missing Cable Bonds	Cable Re-rack	Fire Proofing	Damage to Ladders, Covers, Doors and Structures	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)						
1	0	0	0	0	1	100%
2	620	126	181	0	22	100%
3	0	0	0	44	64	55%
2009 Progress to Date (08/10/09)						
1	0	0	0	0	0	100%
2	484	59	108	0	9	7%
3	0	0	0	17	54	8%

As indicated above, manholes and vaults are examined on a five year cycle per the Inspection & Maintenance program. The manhole and vault asset replacement program will be incorporated into the Inspection & Maintenance program. Please refer to the Inspection and Maintenance Program Strategy document for further details.

Customer Benefits

Potential harm to employees and the public exists from weakening roof structures.

2009 to 2010 Variance Explanation

The “I&M” program identifies issues, but the resulting work on an individual manhole/vault is such that at present it is more effective to have an individual project to manage the work resulting. Repairs to manholes and vaults can be in specific manhole/vault projects or can be included with other underground work. Funding for repairs to manhole/vaults and the underground equipment within them is shown in the table below.

Table IV-15
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,167,000	-	-	-	-	-	
2010 CIP	-	1,650,000	300,000	300,000	600,000	600,000	3,450,000

Major Program Elements

There are currently nine specific vault projects in FY2010/FY2011 and the budgeted spend for each project is less than $200,000. If additional manhole and vault projects are identified through inspection above the I&M budget levels, funds will be allocated as appropriate. The "I&M" program identifies issues, but the resulting work on an individual manhole/vault is such that at present it is more effective to have an individual project to manage the work resulting.

Miscellaneous Underground Equipment

This is a general strategy for miscellaneous equipment in the underground distribution asset group that is not addressed elsewhere by specific strategies. These assets are inspected once every five years through the "I&M" program. These items are considered commodity assets and the grouping includes such item as elbows, joints, grounds, racks, minor transformer and equipment issues, Underground Residential Distribution ("URD") foundations and structures, and anodes. The existing inspection program is to visually inspect for structural defects, missing manhole nomenclature, unmapped facilities, and damaged equipment.

A review of streetlight secondary circuits will be carried out based on the results of a mobile elevated voltage survey. If systemic streetlight and secondary cables issues are identified, funds will be allocated.

Primary Underground Cable

The underground cable asset replacement program replaces distribution cables that are in poor condition. The present strategy is being rewritten to underpin a condition and risk based approach based on cable type, loading and available cable condition information. The new approach will apply new technologies and address replacements proactively, prioritized by condition and risk. This program incorporates the previous "Underground Getaway cable" program.

Drivers:

As reported in the 2009 Asset Condition Report, there are approximately 6,900 circuit miles of underground cable.[66]

Inspection results captured leaking cable/joint issues (Table IV-16).[67]

[66] Report on the Condition of Physical Elements of Transmission and Distribution Systems, October 1, 2009, p. III-110

[67] Ibid, pg. III-110.

Table IV-16
Primary Cable Vault Inspection Results

Level	Cable/Joint Leaking	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)		
1	0	100%
2	18	100%
3	0	100%
2009 Progress to Date (08/10/09)		
1	0	100%
2	8	0%
3	0	100%

Over the 10 year period beginning in 1999, underground cables were the third highest contributor to deteriorated equipment SAIDI/SAIFI, with individual annual average contributions of 0.016 SAIFI and 2.16 minutes SAIDI.

Further information for this program was provided in Exhibit 33.

Customer Benefits

Through a more proactive approach to cable condition analysis and preventative work, a program may reduce the impact of failures but will also limit the possibility of degrading reliability performance

2009 to 2010 Variance Explanation

Identification of individual cables to address, based on condition assessment, type and age, is on-going. In future years the forecast budget reflects both a balanced approach to outage planning for cables and the need to address issues related to permitting and street access (e.g. duct replacement work)

Table IV-17
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	702,000	6,200,000	6,200,000	200,000	200,000	-	12,800,000
2010 CIP	-	3,400,000	4,500,000	3,000,000	4,500,000	6,000,000	21,400,000

Major Program Elements

Replacements are identified through operational and field staff and coordinated through divisional programs. No single element greater than $1,000,000 has been identified at this point.

Underground Getaway Cable

This strategy involves the replacement of underground getaway cables. Underground getaway cables are the lines from a substation to the first overhead structure of a predominately overhead or a mixed overhead/underground circuit. The company seeks to replace these assets based on their individual failure record. Underground getaway cables can be either duct lay or direct buried. Due to the nature of the assets, their condition can not be assessed by visual inspection and thus data is limited.

The strategy for each type of construction is, necessarily, slightly different. Direct buried cables are to be repaired immediately upon its first failure and replaced with a duct lay cable system upon the second failure. Duct lay cables are to be repaired immediately upon its first failure and the entire get-away cable should be replaced upon its second failure.

2009 to 2010 Variance

There is no variance. Future Getaway Cable work will be incorporated with Primary Underground Cable work.

Table IV-18
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	570,000	-	-	-	-	-	-
2010 CIP	-	-	-	-	-	-	-

Underground Residential Distribution Cable

This strategy provides for the repair or replacement of Underground Residential Distribution (URD) cable. The repair/replace decision is based on the performance of each section of URD cable that experiences more than three failures in a half-loop. To date, a small number of cables have met this criterion. There is no inspection program in place that inspects URD cables. The Company has no diagnostic testing to assess the overall health of underground installed cable. Inspections occur once a cable fault has occurred.

2009 to 2010 Variance Explanation

There is no variance. Future URD work will be identified in line with a new condition based strategy which is in draft form at present.

Table IV-19
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	234,000	-	-	-	-	-	-
2010 CIP	-	-	-	-	-	-	-

Oil Fused Cut Outs

As reported in the 2009 Asset Condition Report, all known Oil Fused Cutouts (OFC's) have been removed from service in New York.

If there are any remaining OFCs, these will be located via the Inspection and Maintenance program and removed from service in accordance with the existing strategy.

Asset Condition Replacements Driven by Planning Criteria

The Planning Criteria strategy governs the capacity requirements of the Distribution and Sub-transmission system. The capital work described here is required to meet the planning criteria as a result of other work at a given location based on asset condition.

Drivers

The work identified here is related to asset condition but is driven system planning criteria.

Customer Benefits

The customer benefits relating to these projects will, individually, be small. They are, however, benefits which relate to the application of the Planning Criteria and are described in that strategy.

2009 to 2010 Variance Explanation

There were no identified Planning Criteria capital projects in the 2009 CIP relating to Asset Condition.

Table IV-20
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	1,260,000	1,500,000	1,400,000	-	-	4,160,000

Major Program Elements

There are three separate projects which make up the forecast spend, as shown in the table below.

Table IV-21
Program Elements

Description	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
White Lake Station	800,000	-	-	-	-	800,000
Alps Station New Feeder	100,000	1,500,000	1,400,000	-	-	3,000,000
N. Troy Feeder Getaway	360,000	-	-	-	-	360,000

The addition of substation regulators at White Lake will mitigate low voltage issues and replace a 46 kV recloser and breaker.

The work at Alps station will add area capacity as a consequence of the retirement of Hoag Station.

The addition of a new feeder at North Troy is a consequence of the installation of new Metal Clad station equipment.

Underground Networks

The underground network asset replacement program targets the maintenance, monitoring and installation/replacement of: limiters, transformers, protectors, secondary cables and miscellaneous network assets.

Drivers:

The network systems are an aging infrastructure that requires monitoring, maintenance and replacements to maintain the reliability; when incidents do occur the restoration can end up being very lengthy and costly. There is an environmental requirement to shut down sump pumps in network vaults. Some residual damage is starting to show up as rusting equipment, switching problems, and transformer failures. The program will balance meeting the environmental requirement while maintaining the effected assets.

The Company has initiated a number of studies to analyze the ability of the secondary network cables to clear during fault conditions as a result of previous network incidences.

Load flow studies have also been completed on the Buffalo, Syracuse Ash St, Syracuse Temple St, Watertown and Troy networks.

Further information for this program is provided in Exhibit 47.

Customer Benefits

The approach to networks is one of prevention and proactive intervention. In general when network failures do occur, as in North Troy, they typically require lengthy restoration efforts due to location and feasibility of repairing/replacing equipment and with unexpected civil work.

2009 to 2010 Variance Explanation

The current level of budget forecast supports the deteriorating infrastructure.

Table IV-22
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	-	-	-	-	-	-	-
2010 CIP	-	2,100,000	2,100,000	2,000,000	2,250,000	2,500,000	10,950,000

Major Program Elements

The Albany network improvement scheme is the single largest identifiable project within this program.

Table IV-23
Program Elements

Description	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
Albany Network Equipment	1,500,000	1,500,000	-	-	-	3,000,000

Wood Poles

The basis for the pole replacement strategy is grounded in the I&M program results. The inspection results generate replacement candidates based on condition. This program inspects 20 percent of all poles on a five-year cycle.

2009 to 2010 Variance Explanation

The work identified for candidate pole replacement will be addressed through the "I&M" program.

Table IV-24
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	4,583,000	6,525,000	6,762,000	6,408,000	6,669,000	-	26,394,000
2010 CIP	-	60,000	-	-	-	-	60,000

Miscellaneous Overhead Equipment

This strategy describes an approach for maintaining miscellaneous overhead equipment in the overhead distribution asset grouping. This grouping includes many different asset elements such as guys and anchors, cross-arms, brackets, insulators, insulator pins, braces, lightning arresters, grounds, spacers, connectors, and other devices. These assets are inspected once every five years as part of the "I&M" program.

Items covered by this strategy can be characterized as "commodity" assets. Commodity assets are "low cost" items that are not tracked individually if their condition is found acceptable. While they may not be tracked individually, estimates are made on the number of items. Estimates of these "commodity" assets can be made based on the number of assets inspected. These types of assets are primarily addressed and budgeted in the "I&M" program

Indoor Substations

The Company identified 22 indoor substations located in Buffalo and six indoor substations located in Niagara Falls with asset condition issues as described in the 2009 Asset Condition report. The Buffalo indoor substations that were built in the 1920s through the 1940s are targeted for replacement or refurbishment.

Drivers:

Key drivers for the station rebuilds are a number of personnel safety issues due to the poor condition of the assets discussed in the Company's Asset Condition reports for 2008 and 2009.[68][69] Some issues are highlighted below:

- The 23 kV Condit oil switches do not have the capacity for the fault conditions and have led to injury.
- The 4.16 kV oil circuit breakers requires the operator to be standing at the breaker, they have no provision for proper safety grounding for maintenance.
- The protective relay scheme is of obsolete design, and does not provide adequate protection for some types of faults.
- The primary relays have inappropriate blocking which may lead to extensive damage of primary equipment
- Inadequate transformer bank rating and ventilation

[68]Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2008, p 53.
[69] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pgs. III-122 through III-123.

- The transformer loading at some stations appears to be at or above 100 percent, based on historical allocated capacity values.
- Poor ventilation in transformer bays has led to transformer overheating and possible accelerated aging of insulation as transformer loads have increased.
- Since control, protection, cabling, circuit breakers, and structures are obsolete, a failure of a single component in the substation may not be easily addressed. This situation could cause an extended outage and in many cases the component will have to be replaced.

Further information for this program is provided in Exhibit 48.

Customer Benefits:

This strategy will address safety concerns associated with these indoor substations.

This work is expected to reduce the SAIDI. This improvement is based on a reduction in the mis-operations and addition of automation for control and monitoring

2009 and 2010 Variance Explanation:

The forecast budget associated with Indoor Stations has been recategorized from "Other" in the 2009 CIP report.

Table IV-25
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	11,405,000	-	-	-	-	-	-
2010 CIP	-	8,585,000	13,950,000	17,700,000	17,700,000	17,700,000	75,635,000

Major Program Elements

The sub-transmission chapter discussed overall forecasts for a number of individual stations.

Metalclad Switchgear[70]

This strategy replaces metal clad switchgear installed prior to 1970 beginning with those metalclads that have sustained a failure or are of a manufacturer type where a failure has occurred.[71] There are approximately 220 metalclads in service in NY operating at 13.2kV, 4.16kV and 4.8kV. Of these approximately 70 were installed in the 1960's and 1970's. This strategy plans the replacement of two metalclad substations per year using age and manufacturer as a support to condition assessments being performed using electro-acoustic methods.

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[70] Metalclad Switchgear is a sub-transmission and distribution substation program. See Chapter III for section on "metalclad switchgear. The section provides program details. Also, see Exhibit X for program justification.
[71] Details on this strategy are included as Exhibit 34 in "Transmission and Distribution Capital Investment Plan," October 22, 2007.

Drivers

Several design factors with older vintage metalclad substations contribute to bus failures or component failures. These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the failures of metal-clad switch-gear, substations and busses. Gaskets and caulking of enclosures deteriorate over time allowing rain and melting snow to enter.
- Ventilation - Metalclad interiors can reach high temperatures in the summer even if ventilation systems are working correctly. High temperatures degrade the lubrication in breaker mechanisms and other moving parts, and can cause failure of electronic controls and relays
- Insulation - Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages are apparent in earlier vintage switchgear. This strategy would replace two metalclad substations per year using age and manufacturer as a proxy to conduct condition assessment.

Further information was provided in Exhibit 35.

Customer Benefits:

Though occasional, each metal clad event contributes an average SAIDI value of 0.35 minutes and a SAIFI of 0.002. The impact on local customers is usually more substantial, with almost 3000 customers interrupted for over three hours. Offsetting this interruption is of significant benefit to the customers concerned.

2009 and 2010 Variance Explanation

As noted in the sub-transmission discussion of Metalclad Switchgear, new condition assessment data and analysis has helped identify and prioritize replacement candidates. These have been forecast for the future years.

Table IV-26
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,338,000	-	-	-	-	-	2,338,000
2010 CIP	-	1,250,000	4,875,000	5,025,000	3,000,000	3,000,000	17,150,000

Major Program Elements

Individual stations are targeted for metal clad replacement based on the strategy and condition review. The following stations are in progress, with a statewide program available to prioritize further stations.

Table IV-27
Program Elements

System	Project	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Distribution	Programmed MetalClad Equipment	250,000	1,875,000	2,225,000	3,000,000	3,000,000	10,350,000
Distribution	Altamont Sub Metalclad	850,000	1,500,000	1,400,000	-	-	3,750,000
Distribution	Market Hill Sub Metalclad	150,000	1,500,000	1,400,000	-	-	3,050,000

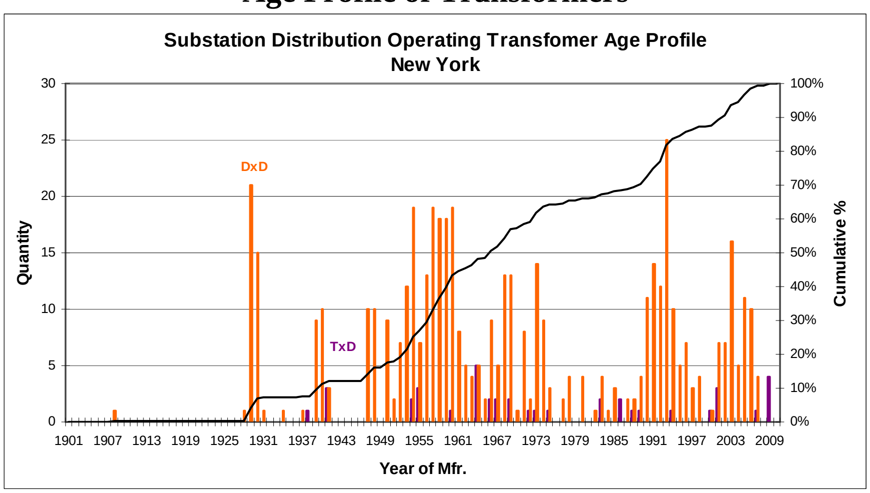
Power Transformers

Power transformers are large capital items, with long lead times and may have significant impact both on reliability and on system capacity. Condition data and condition assessment are the key drivers for identifying replacement candidates – prioritizing replacements through a risk analysis and with feedback from operations.

Drivers

As noted in the 2009 Asset Condition Report, there are approximately 800 power transformers (69kV and below) with an average age of 34 years (Figure IV-3).[72]

Figure IV-3.
Age Profile of Transformers



Each unit is given a condition code as shown in the table below, based on individual transformer test and assessment data, manufacture/design and available operating history.[73] Higher codes relate to transformers which may have anomalous condition; units with a

[72] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pg. III-125.
[73] Ibid, pg. III-127.

higher code are subject to more frequent monitoring and assessment and are candidates for replacement.

Table IV-28
Transformer Condition Codes

Year	Code	1	2	3	4	Total
2009	TRF	757	44	9	6	816
2008	TRF	871	33	4	0	908

At present failure rates of between 0.5 and 1 percent per annum, the Company expects to replace between four and eight units each year. The condition assessment approach identifies units before failure in service with resultant interruptions to service and possible impact on safety and the environment.

Further information for this program is provided in Exhibit 49.

Customer Benefits

Historically, power transformers have provided 2.5 percent of CMI, SAIDI and SAIFI while making up approximately 0.1 percent of events related to deteriorated equipment. By proactively replacing poor condition units there will be direct benefits to customers in reduced impact of power transformers on performance.

2009 and 2010 Variance Explanation

The 2009 Asset Condition Report identifies candidate replacements which have been entered into the forecasts.

Table IV-29
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	2,244,000						
2010 CIP		1,500,000	1,500,000	1,500,000	2,000,000	3,000,000	9,500,000

Major Program Elements

The sub-transmission element of the program reflects work to replace transformer style shunt reactors in NY West which are poor condition. The distribution element covers transformers which are identified as replacement candidates through the test and assessment procedure. A ‘Watch List’ of candidate transformers was identified and recorded in the Asset Condition Report.

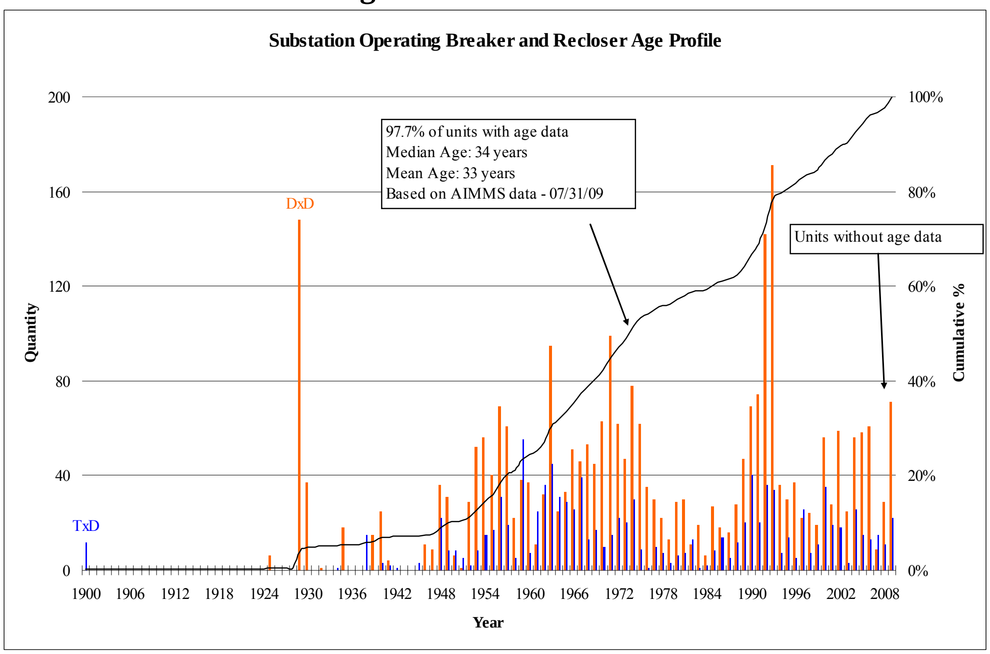
Circuit Breakers and Reclosers

The current strategy for substation circuit breakers and reclosers is based upon a mixture of maintenance, refurbishment and replacement of those assets that are less safe or less reliable due to poor condition, obsolescence or availability of spares.[74] [75]

Drivers:

The Company has 4,106 circuit breakers (4,053 operating and 53 spares) on the distribution system, with an average age of 33 years (Figure IV-4).[76] Aged units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. Likewise, unreliable units have been identified for replacement because their replacement would reduce the number of customer interruptions.

Figure IV-4
Age Profile of Circuit Breakers



The approach for breaker condition coding was based on engineering judgment and experience and was supported by discussion with local field staff. The units are prioritized

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74 Details on this strategy are included as Exhibit 27 in "Transmission and Distribution Capital Investment Plan," October 22, 2007.
75 See the Sub-transmission section on "Circuit Breakers & Reclosers" for program details, and the more detailed justification for this program given in Exhibit 37.

76 Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878, October 1, 2009, pg. III-131.

for replacement based on the condition coding. Many of these breakers are obsolete.[77] Poorer units are given a higher score.

Table IV-30
Condition Code of Circuit Breakers

Condition Code	1	2	3	4	Total
2008 Count	2,159	1,764	158	24	4,105
2009 Count	2,175	1,666	212	0	4,053

The equipment is obsolete.

Breaker failures have resulted in an average of 20 substation events per year in the last five years (as reported in SIR) with an average of 12,000 customers interrupted and 1.5 million customer minutes interrupted. This equates to a SAIFI of 0.007, a SAIDI of 0.96 and a CAIDI of 130.6 minutes.

Customer Benefits:

Several of the targeted breaker families present opportunities to reduce potential hazards associated with safety and the environment (i.e., oil and asbestos).

This strategy will help improve reliability by proactively replacing or refurbishing units with poor reliability or mitigate the risk of future unreliability. Note that:

- "Deteriorated equipment" (reported in the SIR data) makes up ~50 percent of the reliability contribution for breakers
- The program covers a 5 year period to address specific families of breakers
- There is significant year-on-year variability in breaker contributions to reliability statistics

An improvement in the upper limit of 10 percent of current SAIDI/SAIFI related to circuit breakers may be identified: SAIDI ~0.1 and SAIFI ~0.001

2009 and 2010 Variance Explanation

At present the budget forecast reflects units identified in the 2009 Asset Condition report but also takes into consideration the need to address related site issues and cabling – breaker replacement is not a direct one-for-one replacement.

Replacements will be addressed programmatically and identified through the Asset Condition Report.

[77] Ibid, pg. III-122.

Table IV-31
Program Variance ($)

	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP	1,511,000	2,100,000					
2010 CIP		3,500,000	1,750,000	3,500,000	7,000,000	10,000,000	25,750,000

Major Program Elements

The Strategy identifies individual breakers for replacement.

Table IV-32
Program Elements ($)

Substation Circuit Breaker/Recloser		FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total
Distribution	NE ARP Breakers & Reclosers	1,000,000	500,000	1,000,000	2,000,000	3,000,000	7,500,000
Distribution	NC ARP Breakers & Reclosers	1,500,000	750,000	1,500,000	3,000,000	4,000,000	10,750,000
Distribution	NW ARP Breakers & Reclosers	1,000,000	500,000	1,000,000	2,000,000	3,000,000	7,500,000

Batteries and Chargers

The intent of this program is to replace battery and charger systems that are 20 years old (allowing for an extra five years if the battery system tests in good condition) in line with present Substation Maintenance Standards. The 20 year limit is based on industry best practice and our experience in managing battery systems. Battery systems (or sets) are at the heart of a substation's operational capability and the power to charge breaker coils which allow the breaker to operate successfully.

Drivers

Currently, there are over 200 battery sets of which approximately 30 individual sets are known to be in excess of 20 years and 96 sets over 10 years old. To bring all battery systems to less than 20 years within ten years would require a replacement rate of approximately 10 per year, as described in the Substation Battery Strategy[78]. The condition of the Company's

[78] Battery Strategy

batteries and chargers are discussed in the Company's 2009 Asset Condition Report and summarized in the table below.[79]

Table IV-33.
Condition of Battery Population

TYPE	1	2	3	4	Total
BATT	125	65	21	0	211

Individual battery problems may arise at any time – such situations are addressed through the V&O system and through the Problem Identification Worksheet (PIW) system which may be entered at any time. Further details are provided in Exhibit 50.

Customer Benefits

Interruptions related to battery incidents are uncommon as the replacement program is working as desired. An estimated two events annually would produce a total impact of approximately of SAIDI of 0.09 minutes and SAIFI of 0.008.

2009 and 2010 Variance Explanation

This asset class is covered by the Substation Battery and Recharger Strategy but did not appear as a separate section in the 2009 CIP. It is identified here for reference as these are critical items for substation performance.

Table IV-34
Program Variance ($)

Year	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total FY10/11 – FY14/15
2009 CIP							
2010 CIP		475,000	160,000	405,000	825,000	671,000	2,536,000

Major Program Elements

No significant individual elements. This is a station by station replacement of battery systems based on age and condition in line current Substation Maintenance Standards and Procedures

[79] Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-E-0878, October 1, 2009, pg. III-138.

V. OPPORTUNITIES AND RISKS

The Company continues to be committed to investing in its T&D facilities in order to sustain the proactive and systematic approach to asset management that it has adopted and implemented over the past several years, because this approach best ensures most efficient and reliable service to customers now and in the future. In developing the most appropriate investment plan to implement this approach, the Company has and will continue to take into account changed circumstances and new information that may affect its plan. Specifically, the Company will continue to review and adjust its capital investment plan in order to maximize opportunities for greater efficiency while minimizing the impact of those risks that might impair the ability of the Company to meet its goal of providing cost effective, safe, and reliable service to customers. For instance, as discussed above, the current investment plan represents a decrease in overall spending as compared to last year's plan. This decrease was driven in large part by the Company's recognition of the difficult economic circumstances facing its customers. As a result, the Company revised the scope of the investment plan in order to focus on those programs and projects it determined to be essential or required during the period covered by the current investment plan so as to mitigate the impact of potential rate increases. This chapter discusses in further detail other opportunities and risks that impact, or could impact, the Company's capital investment plan, and how the Company has responded to these opportunities and risks.

A. Opportunities

Energy Efficiency and Line Losses

The Company believes that developing and implementing cost-effective energy efficiency measures is sound public policy that should be aggressively pursued. The ability to achieve the goal of reducing electricity usage by 15 percent statewide by 2015 is expected to moderate expected increases in average customer energy bills and the State's overall energy costs over time. Additionally, the 15 percent reduction may enhance system reliability, ease wholesale prices and T&D congestion, reduce greenhouse gas emissions from the energy sector, improve New York's energy security and independence, and create green jobs in New York[80]. Toward that end, a potential source of energy savings that has been identified is the reduction of T&D system losses. The issue of T&D system losses formed the basis for the Commission's July 17, 2008 Order Case 08-E-0751[81] requiring each electric utility to submit a report identifying measures to reduce such system losses and/or optimize T&D system operations. In December 2008, The Company filed its report, in which it identified: (1) measures to reduce all major sources of losses on the Company's T&D system; and (2) measures and programs available to mitigate losses.

[80] See the July 17 Order at 2.

[81] Case 08-E-0751, "Proceeding on Motion of the Commission to Identify the Sources of Electric System Losses and the Means of Reducing Them," Order Clarifying Scope of Proceeding (issued and effective July 17, 2008) (the "July 17 Order").

In that report, the Company has explained that after reviewing a number of options, it discovered that only distribution feeder load balancing produced a favorable benefit-cost analysis. The Company proposed a pilot program for its Eastern Division on the basis of potential loss savings that could be realized by load balancing in the Eastern Division. Should the pilot produce successful results, the Company will evaluate deploying feeder balancing programs to other parts of its service territory. .

In 2009 The Company supported the NYISO's submittal to the Department of Energy (DOE) under the Smart Grid Investment Grant Program for NY State which included a significant component related to integration of new reactive power sources through the installation of additional shunt capacitors. These additional shunt capacitors will enhance the control and coordination of the voltage profile on the New York power grid by providing for additional reactive power resources that can be provided to the bulk power system during system conditions where and when it is needed the most. The NYISO was successful in its submittal to the DOE, and The Company has invested approximately $17M in capacitor banks associated with this stimulus project. .

Furthermore, the Company is continuing to work with the NYISO and other NY Transmission Owners in developing statewide zonal power factor standards that would reduce over-reliance on generation reactive compensation.

Renewable Portfolio Standard

The growth in renewable energy sources, including wind, solar, and biofuels may require additional upgrade and reinforcement of the delivery system to support geographically diverse generation. Such construction may allow the Company to leverage opportunities to improve overall system performance and risk management. Also, any new proposals for renewable generation may change the investment plan moving forward as facilities must be built or upgraded to connect these sources.

Research, Development and Demonstration

The purpose of the Company's RD&D program is to drive innovation through new technologies to improve the efficiency of the Company's electric operations while meeting the challenges and future needs of providing safe, reliable, efficient reasonable cost service to our customers. The program identifies new technologies, tests and evaluates these technologies, and ultimately integrates them into our day-to-day operations. The Company uses a centralized RD&D model to guide, monitor, and report these activities. The objectives of the program are to: 1) reduce customers' costs through reductions in the Company's capital and O&M expenses, 2) improve the reliability of the electric system, and 3) meet the challenges of climate change from a mitigation perspective (e.g., facilitating the integration and interconnection of renewable generation) and an adaptation perspective (creating a better understanding of the impacts of climate change on customers and the electric system).

RD&D efforts underway are looking at the viability and impact of distributed generation and distributed storage devices on the system, as well as the implications of new electro technologies such as electric vehicles. We are also looking extensively at how the Company can reduce its carbon footprint by replacing older less efficient equipment with state-of-the-art technologies and using materials that are less harmful to the environment, as well as reducing our mobile footprint through participation in National programs to demonstrate and deploy hybrid electric vehicles. The Company believes that by applying new methodologies and technologies to the power delivery, we can reduce the overall cost of the business while delivering superior customer value in terms of price and reliability. Other R&D initiatives relating to our T&D system include an evaluation of high-temperature, low-sag conductors and real time thermal rating enabling technologies such as tension monitoring devices, both of which have received funding from NYSERDA. We are also evaluating the impact of standardized data models for protection and control systems.

Specific details of the ongoing and planned projects and expenditures in RD&D are contained in the 2009 Electric Research, Development and Deployment Plan submitted to the commission on April 1, 2009. This is a five year plan submitted annually. It includes details on project expenditures and project results to date.

Demand Side Management

The Company's energy efficiency program efforts will assist customers in managing their energy costs, help to address the state's climate change mitigation goals, and will contribute to the maintenance of the transmission and distribution grid at the lowest cost. The energy efficiency programs will contribute to New York's goal to reduce electric use projected in 2015 by 15 percent. The "15 x 15" goal is the cornerstone of the ongoing Energy Efficiency Portfolio Standard ("EEPS") proceeding in which the Company is an active participant.[82]

Two electric efficiency programs, targeting residential and small commercial customers, began in 2009. The Residential High Efficiency Central Air Conditioning Program promotes the installation of high efficiency central air conditioning equipment. The Small Business Services Energy Efficiency Program provides direct retrofit installation of energy efficient lighting, refrigeration and other unique custom electric energy saving measures.

In 2010, the Company will begin implementation of the following additional six electric efficiency programs:

- The EnergyWise Electric Program will target customers in buildings with between five and fifty dwelling units and provide participants with a complementary comprehensive energy use assessment and financial incentives for actions that will improve the electric energy efficiency in multifamily buildings.
- The Energy Initiative - Large Industrial Electric Program will target industrial customers with electric loads of 2 megawatts or larger and provide technical

[82] Case 07-M-0548, "Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard," Order Instituting Proceeding (issued and effective May 16, 2007).

assistance and incentives to existing industrial facilities to encourage installation of energy efficient measures.

- The Energy Initiative - Mid Sized Electric Program will target non-residential customers with electric demand of less than 2 megawatts and provide technical assistance and incentives to existing facilities to encourage installation of energy efficient measures.

- The Residential ENERGY STAR® Products and Recycling Program will provide incentives to encourage the replacement of inefficient second refrigerators and freezers, windows and thermostats for electrically heated and/or air conditioned homes.

- The Residential Building Practices and Demonstration Program will provide a home energy efficiency paper report and website that benchmark individual customer use compared to use by others in the surrounding neighborhood and use this energy profile to customize customer target offers, coupons, and rebates.

- The Enhanced Home Sealing Incentives Program will target residential customers that heat with electricity in dwellings consisting of one to four units and provide inspections of homes by BPI-certified contractors, who will determine cost-effective opportunities for home owners to reduce energy use, as well as information about potential financial incentives. Program efforts in the period 2009 through 2011 are projected to result in annual energy savings of 559 GWh and summer peak demand savings of 97 MW at the cost of $133 million.

In addition to the above energy and peak demand savings, the Company has projected $33 million of transmission and distribution benefits from these programs over the life of the measures by deferring capital investments in transmission and distribution infrastructure. The Company will continue to explore opportunities to reduce transmission and distribution investment through energy efficiency, consistent with the Commission's directive to investigate, consider and evaluate all reasonable options for alternatives to T&D investments, including distributed generation and energy efficiency."

New York State Transmission Assessment and Reliability Study

The Company continues to be an active participant in the New York State Transmission Assessment and Reliability Study ("STARS"), a joint study of the New York bulk power system being conducted by the state's transmission owners with the full knowledge and support of the NYISO, which is expected to fully complement the NYISO's Comprehensive System Planning Process (CSPP).

The STARS study is investigating the possible needs for future transmission system investments to help ensure a continued reliable and robust electric delivery system to supply the electric power needs of New York's consumers. Phase I of the study has been completed and has identified a need for additional transmission transfer capability to meet statewide reliability requirements under some, but not all, future scenarios. When all three phases of the study is completed, it will identify both needs and strategies for upgrading, refurbishing and/or building new transmission to meet New York reliability and public policy objectives, including accommodating future renewable generation development, modernization of the electric system (“smart grid”) and the advent of plug-in hybrid transport options. Phase II of the study will combine transmission asset condition analysis and evaluate beneficial transmission investments for both reliability needs and renewable resources, and is expected to be complete 2010. Phase III of the study will focus on sensitivity analyses to various parameters such as load growth.

B. Risks

In previous Capital Expenditure filings, the Company addressed some of the potential risks associated with implementing the plan according to anticipated cost and schedule. Many of the same risks remain as well as new risks that have developed in light of the current economic environment.

Access to Credit Markets

For short term credit, National Grid USA (“NGUSA”) operates a commercial paper (“CP”) program which it uses to provide short-term funding for the U.S. operations. In the current market, A1/P1 issuers (i.e., those issuers with the highest short-term ratings) are able to issue freely, subject to name and sector, supported in many cases by the Federal Reserve. NGUSA is rated A2/P2 and is not able to benefit from that support; consequently, its access to the short-term markets is restricted.

Issuers publish interest rates at which they are willing to fund CP, i.e. “post levels”. At present, due to funds raised through alternative markets, NGUSA has not been posting levels. As a guide, current markets would indicate that the cost to NGUSA for issuing CP is the London Interbank Offered Rate (“LIBOR”) plus 7 basis points but tenure would be limited to 1 to 3 months.

For the medium to long term credit, NGUSA operates a European Medium Term Note program, under which it can issue debt which is publicly listed and tradable on the London Stock Exchange. No new issuances under this program have taken place recently. The market is open, but credit spreads for NGUSA are likely to be in excess of 150 basis points over LIBOR[83] for a benchmark sized issue, but there is no certainty that a transaction is possible in the European market for a relatively unknown name. A lower spread may be achievable on small transactions, but none have been printed recently. NGUSA can also issue debt in the U.S., but does not do so because the operating companies can issue debt in the U.S. at lower cost.

[83] The rate would be 1.92969 percent using the December 31 close for 6 month USD LIBOR. However, medium-term notes would be priced off a longer-term LIBOR which may require a higher interest rate, e.g. for 10 years the rate would be 5.47%.

To the extent that the U.S. operating companies have regulatory authority to issue debt, they could do so. Last year, Niagara Mohawk Power Corporation issued $750 million 4.881 percent Fixed Rate Bonds due 2019 and $500 million 3.553 percent Fixed Rate Bonds due 2014. Massachusetts Electric Company issued $800 million 5.90 percent Fixed Rate Bonds due 2039. Credit spreads on these bonds are likely to be approximately 100 to 175 basis points greater than U.S. Treasuries.The spreads indicated above are approximately twice as wide as they would have been two years ago before the worldwide financial crisis began.

NGUSA and its subsidiaries maintain committed, undrawn credit facilities totaling $1.34 billion. These facilities contain no financial covenants and no material adverse change clauses, and all conditions precedent have been fulfilled. This means that these facilities are available for drawing at any time. Drawing these facilities, however, is regarded as a last resort; it would indicate desperation to the market, with serious adverse consequences for the group's future ability to access funding.

In conclusion, although the Company's access to short-term credit continues to be limited, the long-term debt markets are open to the Company. The Company does not anticipate any significant difficulty in being able to fund its businesses. However, volatility in treasury yields and credit spreads will have a very significant effect on the cost of new funding.

Commodity Price Increases/Inflation

It is difficult to predict, with certainty, the near term outlook for material and labor costs in the utility industry. Nevertheless, as required by the September 17, 2007 Order, the Company has reviewed the expenditures included in this plan in light of continued variation in construction and equipment costs. For Distribution, an overall inflation rate of four percent is reflected in blanket project estimates for fiscal year periods FY10/11 through FY14/15. No separate inflation factors were added to individual projects and programs. For transmission projects that have been sanctioned, the inflation rate is included in the specific sanction amount. For transmission and sub transmission projects not yet sanctioned an overall inflation rate of three percent was applied year on year to the five year plan period. This amount balances the significant increases in materials costs for electrical equipment experienced over the past few years with expectations regarding labor costs going forward. In the event that inflation in construction costs exceeds this estimate, the Company's budget would be too low.

The Company continues to monitor and refine its processes for managing commodity shifts and the impact to its current and future capital investments. Some of the major commodities such as oil, copper and steel are showing global upward movements as much as thirty percent over the next few years. Knowing how difficult commodities are to predict, the Company is working with external experts to monitor trends and highlight major shifts, and is continuing to be proactive in implementing risk mitigation strategies to minimize the financial impact of commodity shifts.

Competition for Resources

Competition for the resources required to upgrade T&D facilities has and will continue to increase over the next several years, as utilities across the nation begin to address their aging electric facilities. To mitigate potential resource issues and to leverage a volume spend, the Company has developed the following contract models for the execution of the work.

- Distribution Alliance Contracts. Following a year-long competitive procurement event, Harlan (a subsidiary of Myr Group) was selected to deliver the Upstate New York Electric Distribution line construction program under a fixed-price unit rate agreement over a three-year contract period (with an option to extend two years). Harlan will be evaluated against its unit costs, workload delivery, and specific Key Performance Indicators (KPIs). The release of work in subsequent years is dependent on satisfactory performance against these criteria to ensure acceptable costs and delivery performance.

- Transmission Regional Delivery Ventures (RDVs). The Company has signed a five-year contract (with an option to extend three years), for delivery of Transmission line and substation construction work. The contract includes detailed design, project management and construction services to deliver an assigned portion of the Company's capital investment program. . Pursuant to a competitive selection process, two RDV firms were chosen with one RDV performing work primarily in New York, and the other RDV primarily in New England. In New York, the successful RDV, NorthEast Power Alliance (NEPA), is comprised of a joint venture of Michels, AMEC and Vanderweil Engineering, while in New England, New Energy Alliance (NEA), is comprised of MJ Electric and Balfour Beatty. While focused on either New York or New England, the Company has the right to do work in both regions. The RDV's will be evaluated against its unit costs, workload delivery, and specific Key Performance Indicators (KPIs) including safety performanc. The release of work in subsequent years is dependent on satisfactory performance against these criteria to ensure acceptable costs and delivery performance.

- Internal Construction Capabilities. The Company continues to enhance its own internal transmission and distribution construction capabilities in order to perform a greater portion of the capital program. For the past two years , a dedicated workforce of 30 substation and 30 transmission line workers have been performing construction work on the both the transmission line and substation assets. Additionally, a Distribution Line Construction Pilot (DLC) has been undertaken to create a competitive framework for in-house crews comprised of 55+ line workers to perform distribution construction line work typically performed by contractors. Pilot development began in October 2009, with pilot implementation targeted for April 1, 2010 through April 1, 2011 at which time a decision will be on how best to proceed with this internal construction capability. These new construction capabilities enable an internal workforce to perform a portion of the capital infrastructure investment program while providing for greater visibility of and comparison to the value of work delivered by the external market, enabling benchmarking opportunities to drive further value.

- Traditional "job by job" tendering. The Company will continue to periodically employ the contracting model where contractors are selected on a competitive bid, project by project, basis where applicable to enable the Company to delivery niche services or competitively-priced projects based on unique market conditions.

- "Turn-Key" Engineer, Procure, and Construct (EPC) Events. For specialized installations, the Company will continue to utilize a "turn key" model where complex and specialized equipment is being installed. Examples are, but not limited to, Gas Insulated Substations and Static VAR Compensation units.

Equipment/Material Lead Times

Based on supplier interviews and recent sourcing events, equipment with long construction lead items such as power transformers, CCVTs, breakers, switches and other complex larger equipment, have improved slightly. Lead times for large power transformers that were previously 60+ weeks are now in the low 50 weeks. Though lead times vary by product, in general overall lead times are trending downward.

The improved lead times has been driven by many factors: (i) soft world economy, (ii) soft market and availability of raw commodity materials in Q1-2009, (iii) reduced world wide demand (iv) internal manufacturing efficiencies

To mitigate lead time risk, the Company has established commercially negotiated agreements with preferred vendors based upon their deliverability, cost and quality

Changes in Customer Load or Generator Patterns

Delivery customers and generators may impact the capital plan in four ways. First, existing customer load growth in currently served areas leads to the need for greater delivery capacity over time. Second, residential and commercial/industrial customers move to new locations from older locations. Third, customers and generators request interconnections for new services. Lastly, government agencies may require relocation of facilities to enable public projects such as road widening. The capital investment plan can be affected by all of these. While the impact of load growth is self-explanatory, this section will discuss the last three issues and their possible effect on the capital plan.

In recent history, upstate New York has experienced declining industrial customer load while residential customer load has been growing. Typically, these patterns have not occurred in the same area. For example, city centers have been losing businesses and residences while suburban areas have grown with new residences and commercial industries. In this situation, the Company may have older equipment in the urban area that is losing load while being required to add new facilities to serve new or greater loads in the suburban areas. The old equipment may be facing condition issues that may require replacement for safety, environmental or reliability reasons. Thus, the Company may need to invest in both places to enable reliable service to customers instead of a single investment as new load replaces old load in the urban areas.

An example of a planning issue is when a large potential customer indicates a willingness to move to the service territory. Often, expectations may be created that the large customer will bring significant load from ancillary businesses and new residential development as jobs are created. If the customer fails to locate in the area, The Company will then not invest at the same level. The same issue occurs for expressions of interest to build new generation. Thus, the Company may have a forecast for new generator or customer interconnections but these may fall short of reality. In these difficult economic times, this issue can be exacerbated.

Finally, the Company plays an important role in meeting public requirements work for the State and municipalities. Government agencies request that the Company relocate or reconstruct equipment to allow public requirements work to proceed. The capital investment plan includes estimates for this type of work based upon historical experience. The capital investment plan will be affected if the agencies decide to cut-back or expand their public requirements

The Company's plan makes assumptions regarding customer activity and uses planning, forecasting, and disciplined processes to lessen the fluctuations in investment from customer related changes. However, the Company recognizes that it must adapt to changing circumstances. Thus, the Company approves Programs that consist of multiple projects which allow us to manage the overall capital expenditure plans over the business plan period.

Governmental and Other Approvals

Nearly every T&D capital project requires some level of approval from one or more government agencies or other third parties. For instance, in the Adirondacks, the Department of Environmental Conservation and Adirondack Park Authority are pivotal in approving any construction. Overhead line construction in the public right of way requires permits from local municipalities and/or the Department of Transportation ("DOT"). Obtaining private land, whether for a substation or off road line work (involved in most transmission and sub-transmission projects) requires the Company to purchase land and/or private rights of way from landowners. Local town and village planning boards play a pivotal role in the placement of overhead and underground facilities. Projects in their jurisdiction generally require their support to mitigate the impact of the "not in my back yard" syndrome. Many projects include any number of these approvals from agencies and/or other third parties which can create hurdles to the project schedule and cost. To mitigate this risk, the Company has established a permitting and licensing team with focused expertise in this area.

To obtain the necessary approvals of government agencies and third parties, the scope and configuration of projects often must be changed. This can delay investments and increase costs. To mitigate the risk of these delays and cost increases, the Company is actively working with stakeholders to ensure that the scope of projects is communicated as early as possible and any contentious issues are raised early in the process.

Transmission Outage Scheduling

The Company does not have the final authority to approve outages on elements identified as “controlled” by the NYSIO (*i.e*. lines 230kV and above plus the Edic capacitor). The Company must coordinate those outages through the NYISO process, which can affect the timing of transmission upgrades that require outages for work to be performed reliably and safely. The NYISO may not approve specific transmission line outages due to conflicts with work on other transmission facilities, including those of other transmission owners, impacts on generators or impacts on grid congestion.

For transmission assets that are owned by the Company and are “non-controlled” facilities, the Company is required to notify and coordinate such work with both the NYISO and with other transmission owners. Individual TOs can act unilaterally but in most cases a consensus decision is reached.

The Company is investigating ways to mitigate the risk of not obtaining outage approval, including using different techniques (e.g. using live-line, extended working hours) and scheduling outages further in advance.

VI. EXHIBITS

Exhibit 1 – Projected Five Year Transmission Capital Investment Plan – Program Level

Spending Rationale	Program	FY10/11	FY11/ 12	FY12/ 13	FY13/14	FY14/15	Total
Asset Condition	3A/3B Tower Strategy	-	50,000	150,000	6,100,000	41,000,000	47,300,000
	Battery Strategy	1,206,000	1,206,000	626,000	626,000	626,000	4,290,000
	Circuit Breaker Replacement Strategy	100,000	1,100,000	7,250,000	14,450,000	18,000,000	40,900,000
	Flying Ground Strategy	-	-	250,000	1,000,000	2,000,000	3,250,000
	Other Asset Condition	21,769,471	6,461,160	11,013,075	9,060,233	6,695,000	54,998,939
	Overhead Line Refurbishment Program	20,185,000	32,515,000	53,700,000	92,000,000	77,850,000	276,250,000
	Relay Replacement Strategy	50,000	1,000,000	3,750,000	6,450,000	14,850,000	26,100,000
	RHE Breaker Replacement	100,000	329,000	500,000	-	-	929,000
	Shield Wire Strategy	8,168,000	7,160,000	-	-	-	15,328,000
	Steel Tower Strategy	4,500,000	350,000	-	-	-	4,850,000
	Substation Rebuilds	2,795,000	8,906,000	58,855,000	68,860,000	66,184,090	205,600,090
	Transformer Replacement Strategy	4,000,000	7,000,000	7,000,000	7,000,000	8,966,667	33,966,667
	U-Series Relay Strategy	2,300,110	663,000	-	-	-	2,963,110
	Reserve	(9,000,000)	(9,200,000)	(14,100,000)	(18,579,233)	(16,500,000)	(67,379,233)
Asset Condition Total		**56,173,581**	**57,540,160**	**128,994,075**	**186,967,000**	**219,671,757**	**649,346,573**
Damage/Failure	NY Inspection Projects	400,000	1,000,000	1,000,000	3,000,000	3,000,000	8,400,000
	Other Damage/Failure	3,826,646	2,538,760	3,190,000	3,615,000	3,300,000	16,470,406
	Steel Tower Strategy	125,000	125,000	125,000	125,000	-	500,000
	Wood Pole Strategy	1,750,000	1,500,000	1,600,000	3,000,000	7,900,000	15,750,000
Damage/Failure Total		**6,101,646**	**5,163,760**	**5,915,000**	**9,740,000**	**14,200,000**	**41,120,406**
Non - Infrastructure	Other - Non Infrastructure	-	-	2,000,000	1,100,000	500,000	3,600,000
	Physical Security	100,000	6,000,000	3,000,000	-	-	9,100,000
Non - Infrastructure Total		**100,000**	**6,000,000**	**5,000,000**	**1,100,000**	**500,000**	**12,700,000**
Statutory/Regulatory	Clay Station Rebuild	100,000	2,000,000	2,000,000	-	-	4,100,000
	Clearance Strategy	1,499,000	15,000,000	15,000,000	15,000,000	15,000,000	61,499,000
	Digital Fault Recorder Strategy	1,100,000	-	-	-	750,000	1,850,000
	Generation	114,000	(9,000)	100,000	100,000	100,000	405,000
	Load	887,875	2,000,000	2,000,000	2,000,000	-	6,887,875
	Luther Forest	3,350,898	4,810,080	-	-	-	8,160,978
	Northeast Region Reinforcement	7,342,000	41,160,000	64,993,925	38,450,000	18,898,243	170,844,168
	Other Statutory/Regulatory	825,000	1,950,000	1,750,000	1,400,000	-	5,925,000
	RTU Strategy	1,455,000	2,000,000	1,400,000	-		4,855,000
	Station BPS Upgrades	9,850,000	20,000,000	23,000,000	-	-	52,850,000
	Reserve	(3,200,000)	(10,700,000)	(11,200,000)	(6,600,000)	(2,500,000)	(34,200,000)
Statutory/Regulatory Total		**23,323,773**	**78,211,080**	**99,043,925**	**50,350,000**	**32,248,243**	**283,177,021**
System Capacity & Performance	Frontier Region	29,250,000	54,347,000	12,301,000	5,656,000	5,150,000	106,704,000
	Load	2,087,000	1,837,000	-	-	-	3,924,000
	Other System Capacity & Performance	5,848,000	7,302,000	9,968,000	20,996,000	7,230,000	51,344,000
	Overhead Line Refurbishment Program	5,350,000	-	-	-	-	5,350,000
	Reliability Criteria Compliance	11,566,000	29,799,000	33,278,000	23,091,000	18,000,000	115,734,000
	Reserve	(7,800,000)	(12,200,000)	(4,500,000)	(2,900,000)	(2,000,000)	(29,400,000)
System Capacity & Performance Total		**46,301,000**	**81,085,000**	**51,047,000**	**46,843,000**	**28,380,000**	**253,656,000**
Grand Total		**132,000,000**	**228,000,000**	**290,000,000**	**295,000,000**	**295,000,000**	**1,240,000,000**

Exhibit 2
Projected Five-Year Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
Asset Condition	3A/3B Tower Strategy	Leeds - Pleasant Valley 91/92 Tower Reinforcement - includes	C08017	-	-	50,000	100,000	27,000,000	27,150,000	49
		New Scotland - Leeds 93/94 Tower Reinforcement - Public Sa	C07918	-	50,000	100,000	6,000,000	14,000,000	20,150,000	49
	3A/3B Tower Strategy Total			**-**	**50,000**	**150,000**	**6,100,000**	**41,000,000**	**47,300,000**	
	Battery Strategy	Battery Strategy FY09 Co. 36 Txt	C24239	330,000	330,000	-	-	-	660,000	22
		Battery System Replacement Program	C32957	250,000	250,000	-	-	-	500,000	34
		BatteryRplStrategyCo36TxT	C33847	626,000	626,000	626,000	626,000	626,000	3,130,000	39
	Battery Strategy Total			**1,206,000**	**1,206,000**	**626,000**	**626,000**	**626,000**	**4,290,000**	
	Circuit Breaker Replacement Strategy	Inghams-replace 115kv OCB	C31661	50,000	200,000	1,000,000	5,000,000	5,000,000	11,250,000	35
		Meco - Replace 115kV PTs and circuit breakers	CNYAS24	-	-	250,000	1,000,000	5,000,000	6,250,000	35
		Mortimer 115kV - refurbish / replace circuit breakers	CNYAS39	-	-	-	250,000	-	250,000	35
		NY Circuit Breaker Replacement (Priority 4)	CNYAS07	50,000	900,000	6,000,000	8,000,000	4,000,000	18,950,000	35
		NY Circuit Breaker Replacement Priority 3)	CNYAS06	-	-	-	200,000	4,000,000	4,200,000	26
	Circuit Breaker Replacement Strategy Total			**100,000**	**1,100,000**	**7,250,000**	**14,450,000**	**18,000,000**	**40,900,000**	
	Flying Ground Strategy	Strategy to Replace Flying Ground Switches	CNYX30	-	-	250,000	1,000,000	2,000,000	3,250,000	22
	Flying Ground Strategy Total			**-**	**-**	**250,000**	**1,000,000**	**2,000,000**	**3,250,000**	
	Other Asset Condition	Alps #188 Obsolete Circuit Switcher	C28304	200,000	650,000	-	-	-	850,000	16
		Ash to Teall Cathodic Protection Upgrade	C27082	15,000	70,000	-	-	-	85,000	28
		Bristol Hill Repl SWs 46 & 47	C31005	25,000	167,150	-	-	-	192,150	28
		Butler Sta 64 -RPL LN182	C31950	615,405	-	-	-	-	615,405	43
		Colton Replace CBs and disconnects	C29844	924,000	924,000	924,000	-	-	2,772,000	34
		Dewitt-Rebuild 345kv	C31867	345,001	-	-	-	-	345,001	49
		Dunkirk 230kV Control Cable TB1	C27845	836,000	-	-	-	-	836,000	34
		Edic Station - Replace TB2, 3, 4 Metering	C31025	-	82,845	-	-	-	82,845	40
		EJ West-Warrensburg 9 115kV Cross Bracing	C03383	-	-	-	105,000	-	105,000	16
		Elm Terminal Station - HPFF Alarms	C30528	5,000	130,000	-	-	-	135,000	35
		Elnora 115kV Tap Cross Bracing	C03384	-	-	-	105,000	-	105,000	16
		Fenner-Cortland 3 Cross Braces.	C03281	-	-	-	102,233	-	102,233	21
		Gardenville Control Cables	C27829	300,000	-	-	-	-	300,000	34
		Gardenville Station - HPFF Alarms	C30530	10,000	125,000	-	-	-	135,000	35
		Gibson Sta - Repl SW1602,03, R1617,18	C31004	66,000	252,075	252,075	-	-	570,150	28
		Greenbush- Replace TB3	C31663	25,000	575,000	1,000,000	-	-	1,600,000	39
		Harper Station - Replace 2023 & 2033 MODs	C29950	-	120,000	347,000	-	-	467,000	22
		Huntley Station - HPFF Alarming	C30531	10,000	125,000	-	-	-	135,000	35
		Lafayette - Replace Line 4 Relaying	C28044	90,000	-	-	-	-	90,000	39
		Leeds SVC-Refurbishment/Replacement	C03748	5,854,000	-	-	-	-	5,854,000	36
		New Gardenville - TB3 &TB#4	C27042	3,700,000	-	2,800,000	2,800,000	-	9,300,000	34
		NY Surge Arrester Replacement	C31658	-	25,000	2,725,000	2,550,000	2,630,000	7,930,000	36
		Oswego - Replace Special	C29216	25,000	664,450	-	-	-	689,450	35
		Packard Replace TB3 &TB4	C27006	6,447,000	-	-	-	-	6,447,000	41
		PIW Prospective Projects	CNYX72	1,000,000	1,500,000	1,500,000	3,000,000	3,000,000	10,000,000	49
		Porter Replace 11 GE 230kV RF2 Discs	C20912	450,000	445,000	-	-	-	895,000	28
		Rochester Generator and HPFF Alarms	C30532	10,000	125,000	-	-	-	135,000	39
		Rochester HPFF Cable Plant	C15988	-	30,000	903,000	123,000	-	1,056,000	44
		Rochester Pump - LPFF Trip Scheme	C29946	-	35,000	387,000	-	-	422,000	35
		Silver Creek switch structure - replace 115kV disconnects	CNYAS38	-	-	-	250,000	1,000,000	1,250,000	21
		Taylorville Repl SW #23	C31044	25,000	55,640	-	-	-	80,640	34
		Temple Pressuring Plant	CNYX26	-	-	-	25,000	65,000	90,000	28
		Ticonderoga-Sanford T6410R Removal	C32309	12,500	50,000	175,000	-	-	237,500	43
		Trinity UG Pumphouse Redesign	C11318	690,000	310,000	-	-	-	1,000,000	49
		Youngmann Terminal Station - Replace Switch #310	C29951	89,565	-	-	-	-	89,565	19
	Other Asset Condition Total			**21,769,471**	**6,461,160**	**11,013,075**	**9,060,233**	**6,695,000**	**54,998,939**	
	Overhead Line Refurbishment Program	Dunkirk - Falconer #161	CNYAS62	-	-	100,000	50,000	-	150,000	40
		Dunkirk - Falconer #162	CNYAS49	100,000	50,000	200,000	1,000,000	14,000,000	15,350,000	44
		Falconer-HH 153-154, T1160-T1170 ACR	C27422	-	50,000	200,000	1,000,000	-	1,250,000	39
		Gard-Dun 141-142 T1260-1270 ACR	C03389	500,000	9,000,000	27,000,000	15,000,000	-	51,500,000	44
		Gardenville - Buffalo Sw #146 [145]	CNYAS60	-			100,000	50,000	150,000	18
		Gardenville - Dunkirk #74	CNYAS75	-	-	100,000	50,000	-	150,000	40
		Gardenville -HH 151-152, T1950-T1280-S ACR	C27425	100,000	100,000	1,000,000	1,000,000	15,800,000	18,000,000	39
		Gardenville Lines 180-182, T1660-T1780 ACR	C27436	50,000	50,000	50,000	12,500,000	4,000,000	16,650,000	44
		Gard-HHl 151-152, T1950-T1280 N ACR	C04718	9,910,000	6,720,000	-	-	-	16,630,000	49
		Homer Hill Bennett Rd 157, T1340 ACR	C27429	50,000	50,000	50,000	100,000	-	250,000	39
		Huntley - Lockport #37	CNYAS53	100,000	50,000	50,000	100,000	-	300,000	44
		Huntley - Praxair #46	CNYAS51	-	100,000	100,000	100,000	-	300,000	18
		Huntley-Gardenville 38 [& 39] (refurb)	CNYAS63	-	-	-	100,000	-	100,000	40
		Indeck Oswego - Lighthouse Hill #2	CNYAS56	100,000	50,000	50,000	6,000,000	10,000,000	16,200,000	39

Exhibit 2
Projected Five-Year Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		Lockport 103- 104, T1620-T106 STR	C27432	100,000	50,000	50,000	100,000	8,000,000	8,300,000	40
		Lockport Mortimer 111 T1530 ACR	C03417	1,550,000	12,000,000	21,000,000	12,000,000	-	46,550,000	49
		Lockport-Batavia 112, T1510 ACR	C03422	-	200,000	2,500,000	12,300,000	-	15,000,000	39
		Lockport-Bativa 108 Refurb	C27431	-	100,000	50,000	50,000	-	200,000	29
		Lockport-Mort 113-114, T1540-T1550 LER	C18670	1,840,000	-	-	-	-	1,840,000	49
		Lockprt-Mort 111 Tap T1530-1 Refurb	C33014	5,000	95,000	300,000	-	-	400,000	39
		Mortimer - Pannell Road #24	CNYAS65	-	100,000	50,000	50,000	-	200,000	40
		Pannell-Geneva 4-4A, T1860 ACR	C30889	50,000	50,000	100,000	14,100,000	-	14,300,000	37
		Porter - Rotterdam #30	CNYAS77	-	-	-	50,000	-	50,000	40
		Porter Rotterdam 31, T4210 ACR	C30890	100,000	100,000	100,000	9,850,000	16,000,000	26,150,000	45
		Taylorville -B 5-6 T3320-T3330 ACR	C27437	50,000	100,000	600,000	5,400,000	-	6,150,000	39
		Taylorville-Moshier 7, T3340 ACR	C24361	2,420,000	3,500,000	-	-	-	5,920,000	49
		Ticonderoga Lines 2 [& 3] (Complete Line)	CNYAS82	-	-	50,000	1,000,000	10,000,000	11,050,000	40
		Ticonderoga-2-3, T5810-T5830 SXR	C19530	3,160,000	-	-	-	-	3,160,000	49
	Overhead Line Refurbishment Program Total			**20,185,000**	**32,515,000**	**53,700,000**	**92,000,000**	**77,850,000**	**276,250,000**	
	Relay Replacement Strategy	Browns Falls - protection repalcement and new control buildin	CNYAS29	-	-	-	-	100,000	100,000	19
		Edic - Protection replacement	CNYAS31	-	-	100,000	500,000	500,000	1,100,000	19
		Geres lock Control room & Relay Strategy	CNYAS90	-	-	-	-	250,000	250,000	19
		Menands - new control building	CNYAS41	-	250,000	250,000	1,000,000	5,000,000	6,500,000	28
		North Troy - protection replacement	CNYAS26	-	-	-	100,000	500,000	600,000	19
		NY Protection & Control Replacement	CNYAS10	50,000	750,000	3,300,000	4,250,000	4,250,000	12,600,000	35
		Oswego - new control building	CNYAS32	-	-	100,000	500,000	500,000	1,100,000	19
		Relay Replacement Strategy - Phase 2	CNYAS88	-	-	-	-	3,000,000	3,000,000	19
		Riverside Control room & Relay Strategy	CNYAS89	-	-	-	-	250,000	250,000	19
		Yahnundasis - protection replacement	CNYAS28	-	-	-	100,000	500,000	600,000	19
	Relay Replacement Strategy Total			**50,000**	**1,000,000**	**3,750,000**	**6,450,000**	**14,850,000**	**26,100,000**	
	RHE Breaker Replacement	Lighthouse Hill Road - Repl R60 RHE PCB	C24299	100,000	229,000	-	-	-	329,000	39
		Oneida - R/R 115kV FP RHE OCB's	C18410	-	100,000	500,000	-	-	600,000	39
	RHE Breaker Replacement Total			**100,000**	**329,000**	**500,000**	**-**	**-**	**929,000**	
	Shield Wire Strategy	Shieldwire: Buffalo 145	C28683	330,000	1,260,000	-	-	-	1,590,000	40
		Shieldwire: Clay-Dewitt 3	C28709	1,200,000	1,200,000	-	-	-	2,400,000	40
		Shieldwire: Gardenville -Depew 54	C28706	20,000	1,110,000	-	-	-	1,130,000	40
		Shieldwire: Gardenville Homer 151/152	C28679	-	3,590,000	-	-	-	3,590,000	40
		Shieldwire: Huntley - Gardenville 38	C28676	1,501,000	-	-	-	-	1,501,000	40
		Shieldwire: Huntley-Lockport 36/37	C28707	1,514,000	-	-	-	-	1,514,000	40
		Shieldwire: LaFarge Pleasant Vl. 8	C28678	1,710,000	-	-	-	-	1,710,000	40
		Shieldwire: Mountain-Lockport 103	C28681	1,289,000	-	-	-	-	1,289,000	40
		Shieldwire: Walck Rd - Huntley	C28712	604,000	-	-	-	-	604,000	40
	Shield Wire Strategy Total			**8,168,000**	**7,160,000**	**-**	**-**	**-**	**15,328,000**	
	Steel Tower Strategy	S. Oswego Lighthouse Hill Circuits	C21693	4,500,000	350,000	-	-	-	4,850,000	49
	Steel Tower Strategy Total			**4,500,000**	**350,000**	**-**	**-**	**-**	**4,850,000**	
	Substation Rebuilds	Buffalo 115kV - replace disconnects	CNYAS40	-	-	-	250,000	-	250,000	21
		Dunkirk Rebuild	C05155	-	-	140,000	500,000	7,000,000	7,640,000	35
		Elm St. Refurbishment	CNYAS91	-	-	500,000	1,000,000	1,000,000	2,500,000	35
		Gardenville Rebuild	C05156	500,000	2,660,000	36,430,000	22,960,000	184,090	62,734,090	35
		Gardenville Rebuild Line Location	C30084	1,000,000	1,196,000	1,310,000	50,000	-	3,556,000	44
		LightHH 115kv Yard Repl & cntrl hse	C31662	250,000	1,000,000	5,000,000	5,000,000	-	11,250,000	35
		Lockport Rebuild	CNYAS2	-	-	250,000	1,000,000	10,000,000	11,250,000	35
		Mohican - rebuild including transformers and oil circuit breake	CNYAS44	50,000	200,000	1,000,000	10,000,000	-	11,250,000	35
		N. Leroy Rebuild Station	C29180	120,000	-	-	-	-	120,000	34
		Porter 230kV - replace disconnects and PTs	CNYAS36	-	250,000	1,000,000	10,000,000	-	11,250,000	28
		Reynolds Road - protection repalcement & new control buildin	CNYAS27	-	-	500,000	1,000,000	1,000,000	2,500,000	19
		Rome 115 kV Station	C03778	375,000	2,000,000	8,725,000	2,100,000	-	13,200,000	22
		Rotterdam R/R 230kV FPE RHE CB's	C17849	500,000	1,600,000	4,000,000	15,000,000	47,000,000	68,100,000	39
	Substation Rebuilds Total			**2,795,000**	**8,906,000**	**58,855,000**	**68,860,000**	**66,184,090**	**205,600,090**	
	Transformer Replacement Strategy	NY 115kv Transformer Replace (Priority 4)	C31656	4,000,000	7,000,000	7,000,000	7,000,000	8,966,667	33,966,667	41
	Transformer Replacement Strategy Total			**4,000,000**	**7,000,000**	**7,000,000**	**7,000,000**	**8,966,667**	**33,966,667**	
	U-Series Relay Strategy	Edic FE1 - Replace U Series Relays	C24662	302,110	-	-	-	-	302,110	33
		Leeds - Replace U Series Relays	C24663	190,000	663,000	-	-	-	853,000	33
		LN17- Replace Type U Relays	C24661	1,350,000	-	-	-	-	1,350,000	33
		Westinghouse U Series Relay Strategy	C05150	458,000	-	-	-	-	458,000	33
	U-Series Relay Strategy Total			**2,300,110**	**663,000**	**-**	**-**	**-**	**2,963,110**	
	Reserve	Resreve	CNYX31	(9,000,000)	(9,200,000)	(14,100,000)	(18,579,233)	(16,500,000)	(67,379,233)	49
	Reserve Total			**(9,000,000)**	**(9,200,000)**	**(14,100,000)**	**(18,579,233)**	**(16,500,000)**	**(67,379,233)**	
Asset Condition Total				**56,173,581**	**57,540,160**	**128,994,075**	**186,967,000**	**219,671,757**	**649,346,573**	
Damage/Failure	NY Inspection Projects	NY Inspection Projects - Capital	C26923	400,000	1,000,000	1,000,000	3,000,000	3,000,000	8,400,000	49
	NY Inspection Projects Total			**400,000**	**1,000,000**	**1,000,000**	**3,000,000**	**3,000,000**	**8,400,000**	

Exhibit 2
Projected Five-Year Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
	Other Damage/Failure	Curtis St- Repl LN10 &13 Relays	C29320	-	173,760	-	-	-	173,760	26
		Geres Lock Sub- Repl 14 115kV Disc	C28324	324,875	-	-	-	-	324,875	19
		Getzville-Sta60-Repl Cntrl Hse Roof	C32504	8,000	-	-	-	-	8,000	35
		Kensington Sub Repl TB#4 & 5 LTC Control	C28303	10,000	-	-	-	-	10,000	28
		Leeds - PV 92 T5330 Str 361	C32964	25,000	475,000	-	-	-	500,000	40
		New Gardenville-Repl 230kV Discs	C20546	100,000	-	-	-	-	100,000	27
		Oneida - TB#3 Failure	C22391	758,171	-	-	-	-	758,171	49
		Oneida Sub- Replace LTG & Recpt Ckts	C28964	180,600	-	-	-	-	180,600	16
		Porter Sub - Repl. Barre neutr & Auto	C32596	20,000	-	-	-	-	20,000	35
		Replace Damaged Insulators	C31660	360,000	20,000	20,000	20,000	-	420,000	40
		S. Oswego R/R LN1 Tone Package	C18952	220,000	-	-	-	-	220,000	33
		Transmission Line Replacements - Budgetary Reserve	C03278	200,000	200,000	200,000	200,000	-	800,000	49
		Transmission Station Failures - Budgetary Reserve	C03792	1,000,000	1,400,000	2,700,000	3,100,000	3,300,000	11,500,000	49
		Transmission Storm Budgetary Reserve	C03481	250,000	250,000	250,000	275,000	-	1,025,000	49
		Transmission UG C Budgetary Reserve - Co 36	C13622	20,000	20,000	20,000	20,000	-	80,000	49
		Yahnundasis - Repl 18 & 28 Switches	C26144	350,000	-	-	-	-	350,000	28
	Other Damage/Failure Total			**3,826,646**	**2,538,760**	**3,190,000**	**3,615,000**	**3,300,000**	**16,470,406**	
	Steel Tower Strategy	Visual Grade 6 Tower Replacements	C25539	125,000	125,000	125,000	125,000	-	500,000	40
	Steel Tower Strategy Total			**125,000**	**125,000**	**125,000**	**125,000**	**-**	**500,000**	
	Wood Pole Strategy	Wood Pole Management - NY	C11640	1,750,000	1,500,000	1,600,000	3,000,000	7,900,000	15,750,000	43
	Wood Pole Strategy Total			**1,750,000**	**1,500,000**	**1,600,000**	**3,000,000**	**7,900,000**	**15,750,000**	
Damage/Failure Total				**6,101,646**	**5,163,760**	**5,915,000**	**9,740,000**	**14,200,000**	**41,120,406**	
Statutory/Regulatory	Clay Station Rebuild	Clay Station Line Project	C32539	100,000	2,000,000	2,000,000	-	-	4,100,000	49
	Clay Station Rebuild Total			**100,000**	**2,000,000**	**2,000,000**	**-**	**-**	**4,100,000**	
	Clearance Strategy	Oswego Lafayette 17, T2420 CCR	C31141	549,000	-	-	-	-	549,000	33
		Transmission Tower Clearances	C03256	950,000	15,000,000	15,000,000	15,000,000	15,000,000	60,950,000	40
	Clearance Strategy Total			**1,499,000**	**15,000,000**	**15,000,000**	**15,000,000**	**15,000,000**	**61,499,000**	
	Digital Fault Recorder Strategy	Digital Fault Recorder Strategy	C03726	1,100,000	-	-	-	-	1,100,000	49
		Repl DFR at Non-BPS Stations	C29487	-	-	-	-	750,000	750,000	27
	Digital Fault Recorder Strategy Total			**1,100,000**	**-**	**-**	**-**	**750,000**	**1,850,000**	
	Generation	Alabama Ledge Wind-Loop in, Loop-out	CNYX63	190,000	241,000	-	-	-	431,000	49
		Alabama Ledge Wind-Loop in, Loop-out Reimburseable portio	CNYX63R	(190,000)	(350,000)	-	-	-	(540,000)	49
		Alabama Ledge Wind-RTU/Metering/Relay upgrades	CNYX64	960,000	652,000	-	-	-	1,612,000	49
		Alabama Ledge Wind-RTU/Metering/Relay upgrades-Reimbu	CNYX64R	(960,000)	(652,000)	-	-	-	(1,612,000)	49
		Athens Generation Expansion -Permanent Line	CNYX01	6,000,000	10,400,000	25,500,000	26,100,000	-	68,000,000	1
		Athens Generation Expansion -Permanent Line Reimbursable	CNYX01R	(6,000,000)	(10,400,000)	(25,500,000)	(26,100,000)	-	(68,000,000)	1
		Athens Generation Expansion -Permanent Sub	CNYX02	-	-	500,000	3,400,000	-	3,900,000	1
		Athens Generation Expansion -Permanent Sub Reimbursable	CNYX02R	-	-	(500,000)	(3,400,000)	-	(3,900,000)	1
		BEDCO Substation Work	C23413	100,000	-	-	-	-	100,000	49
		Cape Vincent Wind-RTU/Metering/Relay upgrades	CNYX60	75,000	2,730,000	-	-	-	2,805,000	49
		Cape Vincent Wind-RTU/Metering/Relay upgrades-Reimburs	CNYX60R	(75,000)	(2,730,000)	-	-	-	(2,805,000)	49
		Clayton Wind-Loop in, Loop-out	CNYX70	350,000	2,000,000	-	-	-	2,350,000	49
		Clayton Wind-Loop in, Loop-out Reimburseable portion	CNYX70R	(350,000)	(2,000,000)	-	-	-	(2,350,000)	49
		Clayton Wind-RTU/Metering/Relay upgrades	CNYX71	320,000	1,000,000	-	-	-	1,320,000	49
		Clayton Wind-RTU/Metering/Relay upgrades-Reimbursable p	CNYX71R	(320,000)	(1,000,000)	-	-	-	(1,320,000)	49
		Fairfield Wind Farm Interconnection	C29583	800,000	-	-	-	-	800,000	49
		Fairfield Wind Farm Interconnection - Reimbursbale Portion	C29583R	(800,000)	-	-	-	-	(800,000)	49
		Fairfield Wind-loop in loop out	C29782	1,000,000	-	-	-	-	1,000,000	49
		Fairfield Wind-loop in loop out(reimb)	C29782R	(1,000,000)	-	-	-	-	(1,000,000)	49
		Green Power-Cody Rd-loop in,loop out	CNYX68	479,000	-	-	-	-	479,000	49
			CNYX68R	(539,000)	-	-	-	-	(539,000)	49
		Green Power-Cody Rd-RTU,metering	CNYX69	956,000	-	-	-	-	956,000	49
			CNYX69R	(982,000)	-	-	-	-	(982,000)	49
		Inghams SPS updates	CNYPL3	100,000	100,000	100,000	100,000	100,000	500,000	40
		Jordanville Wind-Loop in,Loop out	CNYX53	150,000	500,000	-	-	-	650,000	49
		Jordanville Wind-Loop in,Loop out Reimbursable Portion	CNYX53R	(150,000)	(500,000)	-	-	-	(650,000)	49
		Jordanville Wind-RTU/metering/Relay upgrades	CNYX54	176,000	2,300,000	-	-	-	2,476,000	49
		Jordanville Wind-RTU/metering/Relay upgrades Reimbursabl	CNYX54R	(176,000)	(2,300,000)	-	-	-	(2,476,000)	49
		New Grange Wind-Loop in, Loop-out	CNYX65	400,000	420,000	-	-	-	820,000	49
		New Grange Wind-Loop in, Loop-out Reimburseable portion	CNYX65R	(400,000)	(420,000)	-	-	-	(820,000)	49
		New Grange Wind-RTU/Metering/Relay upgrades	CNYX66	1,340,000	1,055,000	-	-	-	2,395,000	49
		New Grange Wind-RTU/Metering/Relay upgrades-Reimbursal	CNYX66R	(1,340,000)	(1,055,000)	-	-	-	(2,395,000)	49
		Noble Bliss 1 - New Arcade Tap	C27745	306,000	-	-	-	-	306,000	49
		Noble Bliss 1 - New Arcade Tap - Reimbursable Portion	C27745R	(306,000)	-	-	-	-	(306,000)	49
		Noble Bliss Wind Farm	C24981	50,000	-	-	-	-	50,000	35
		Noble Bliss Wind Farm - Reimbursbale Portion	C24981R	(50,000)	-	-	-	-	(50,000)	49
		Sherman Island Uprate-RTU/Metering/Relay upgrades	CNYX67	760,000	-	-	-	-	760,000	49

Exhibit 2
Projected Five-Year Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		Sherman Island Uprate-RTU/Metering/Relay upgrades-Reimbu	CNYX67R	(760,000)	-	-	-	-	(760,000)	49
		St Lawrence Wind-Loop in, Loop-out	CNYX55	100,000	900,000	-	-	-	1,000,000	49
		St Lawrence Wind-Loop in, Loop-out Reimburseable Portion	CNYX55R	(100,000)	(900,000)	-	-	-	(1,000,000)	49
		St Lawrence Wind-RTU/Metering/Relay upgrades	CNYX56	600,000	1,600,000	-	-	-	2,200,000	49
		St Lawrence Wind-RTU/Metering/Relay upgrades-Reimbursab	CNYX56R	(600,000)	(1,600,000)	-	-	-	(2,200,000)	49
		WestHill Wind -Loop in-loop out	CNYX49	372,500	-	-	-	-	372,500	49
		WestHill Wind -Loop in-loop out Reimbursable Portion	CNYX49R	(372,500)	-	-	-	-	(372,500)	49
		WestHill Wind -RTU/metering	CNYX50	600,000	-	-	-	-	600,000	49
		WestHill Wind-RTU/metering Reimbursable Portion	CNYX50R	(600,000)	-	-	-	-	(600,000)	49
	Generation Total			**114,000**	**(9,000)**	**100,000**	**100,000**	**100,000**	**405,000**	
	Load	New Distribution for Load Growth	CNYPL8	200,000	2,000,000	2,000,000	2,000,000	-	6,200,000	30
		Reynolds Road 115-13.2Kv Second Bank	C27423	687,875	-	-	-	-	687,875	35
		Unifax	C29824	103,333	206,667	-	-	-	310,000	49
		Unifax -Reimbursbale Portion	C29824R	(103,333)	(206,667)	-	-	-	(310,000)	49
	Load Total			**887,875**	**2,000,000**	**2,000,000**	**2,000,000**	**-**	**6,887,875**	
	Luther Forest	Luther Forest Relay and Malta Sub work	C22738	3,350,898	4,810,080	-	-	-	8,160,978	49
	Luther Forest Total			**3,350,898**	**4,810,080**	**-**	**-**	**-**	**8,160,978**	
	Northeast Region Reinforcement	Design/Build NERR	CNYX39	470,000	5,000,000	13,433,925	11,920,000	18,098,243	48,922,168	36
		Re-conductor Rotterdam 1&2 Lines - Part of NERR	C18250	3,042,000	-	-	-	-	3,042,000	49
		Rotterdam Banks - Part of NERR	CNYX39A	-	-	1,300,000	17,700,000	800,000	19,800,000	36
		Spier Rotterdam Line#3 - Part of NERR	C31418	1,580,000	9,660,000	25,260,000	8,630,000	-	45,130,000	49
		Turner Rd new 230-115kV Station - Part of NERR	C31326	2,000,000	25,000,000	17,250,000	150,000	-	44,400,000	49
		Turner Road New Line Taps - Part of NERR	C31419	250,000	1,500,000	7,750,000	50,000	-	9,550,000	49
	Northeast Region Reinforcement Total			**7,342,000**	**41,160,000**	**64,993,925**	**38,450,000**	**18,898,243**	**170,844,168**	
	Other Statutory/Regulatory	Repl 23 meters Interconnect/ NYISO	C29483	750,000	1,950,000	1,750,000	1,400,000	-	5,850,000	49
		Various Station - Range Operations	C32551	75,000	-	-	-	-	75,000	49
	Other Statutory/Regulatory Total			**825,000**	**1,950,000**	**1,750,000**	**1,400,000**	**-**	**5,925,000**	
	RTU Strategy	RTU Replacements NERC, EMS, Obsolescence	C03772	1,455,000	2,000,000	1,400,000	-		4,855,000	49
	RTU Strategy Total			**1,455,000**	**2,000,000**	**1,400,000**	**-**		**4,855,000**	
	Station BPS Upgrades	Porter - 115kV upgrade to bulk power	C28686	100,000	12,000,000	12,000,000	-	-	24,100,000	40
		Upgrade 115kV Clay Sub to BPS NPCC	C28705	9,750,000	8,000,000	11,000,000	-	-	28,750,000	49
	Station BPS Upgrades Total			**9,850,000**	**20,000,000**	**23,000,000**	**-**	**-**	**52,850,000**	
	Reserve	Resreve	CNYX32	(3,200,000)	(10,700,000)	(11,200,000)	(6,600,000)	(2,500,000)	(34,200,000)	49
	Reserve Total			**(3,200,000)**	**(10,700,000)**	**(11,200,000)**	**(6,600,000)**	**(2,500,000)**	**(34,200,000)**	
Statutory/Regulatory Total				**23,323,773**	**78,211,080**	**99,043,925**	**50,350,000**	**32,248,243**	**283,177,021**	
System Capacity & Performance	Frontier Region	Refurbishment of Huntley 230kV Station	C11496	-	-	100,000	2,300,000	5,150,000	7,550,000	22
		Tonawanda Station - Line Work	C11494	6,150,000	23,000,000	3,700,000	356,000	-	33,206,000	49
		Tonawanda Station - Station Work	C11495	23,100,000	31,347,000	8,501,000	3,000,000	-	65,948,000	49
	Frontier Region Total			**29,250,000**	**54,347,000**	**12,301,000**	**5,656,000**	**5,150,000**	**106,704,000**	
	Load	Frankhauser New Station - T Line Work	C30744	230,000	365,000	-	-	-	595,000	41
		Install Second Transformer - Inman Rd	C30765	857,000	856,000	-	-	-	1,713,000	39
		Replace TB#1 - Everett Rd	C30824	1,000,000	616,000	-	-	-	1,616,000	30
	Load Total			**2,087,000**	**1,837,000**	**-**	**-**	**-**	**3,924,000**	
	Other System Capacity & Performance	Albany Steam - Add 2nd Station svc	C22071	150,000	200,000	-	-	-	350,000	16
		BlackRiver-LHHX5-2 LB Attachment	C33744	10,000	90,000	-	-	-	100,000	49
		BlackRiver-Taylorville#2 New Switch	C33742	30,000	270,000	-	-	-	300,000	43
		Boonville-Rome #4 Reconductoring	CNYPL4	-	-	100,000	5,000,000	-	5,100,000	40
		Dewitt 345kV Breaker Install	C21353	-	820,000	630,000	-	-	1,450,000	6
		East Watertown 115 Mobile tap	C32337	-	100,000	219,000	-	-	319,000	49
		Eastern NY 115kV Capacitor Additions	CNYPL7	-	-	100,000	2,000,000	-	2,100,000	35
		Farmington 11 Line Rearrangement	C28384	1,487,322	45,709	-	-	-	1,533,031	49
		Farmington 11 Line Rearrangement - Reimb portion	C28384R	(1,487,322)	(45,709)	-	-	-	(1,533,031)	49
		Fourth Elm 230-23kV Bank (N-1-1)	CNYPL14	-	-	-	100,000	650,000	750,000	28
		Fourth Sawyer 230-23kV Bank (N-1-1)	CNYPL13	-	-	-	100,000	650,000	750,000	26
		Install Capacitance/TRV	CNYPL34	-	-	300,000	700,000	400,000	1,400,000	33
		Install new Alps Site Sub- Nassau	C30806	1,113,000	809,000	-	-	-	1,922,000	27
		Install new Alps Site Sub-Line Work	C33619	50,000	150,000	150,000	-	-	350,000	49
		Lake Colby - Spare SVC Transformer and Thyristor Reactor	CNYPL29	100,000	1,660,000	-	-	-	1,760,000	28
		Lowville Automated 115 kV Switches	C32259	100,000	219,000	-	-	-	319,000	49
		LTC Filtration Systems NY	C24064	75,000	-	-	-	-	75,000	21
		Reconductor 24 & 25 Line - Hogan Taps to Panell Road	CNYPL33	-	-	100,000	1,500,000	1,000,000	2,600,000	35
		Reconductor Black River LHH	CNYPL1	-	-	100,000	5,000,000	-	5,100,000	40
		Replace N. Angola 115:34.5kV Banks	C27163	-	384,000	5,320,000	-	-	5,704,000	36
		Replace overdutied 115kV breakers at Central and Mohawk Va	CNYPL26	-	200,000	1,000,000	1,800,000	-	3,000,000	39
		Replace overdutied 115kV breakers at Maplewood	CNYPL25	-	200,000	1,000,000	1,800,000	-	3,000,000	39
		Replace three 115kV breakers at ALCOA	CNYPL24	-	-	300,000	600,000	600,000	1,500,000	39
		Reynolds Road - Cap Blocking Scheme	C29964	20,000	-	-	-	-	20,000	28

Exhibit 2

Projected Five-Year Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		Spier West 9 115kv Switch Add	C30826	-	-	114,000	201,000	-	315,000	34
		Sta Homer Hill Transformers	C10705	-	-	-	200,000	900,000	1,100,000	20
		Syracuse Area Reconductoring	CNYPL28	-	-	300,000	1,600,000	1,600,000	3,500,000	19
		Transmission Study Budgetary Reserve -NY	C08376	200,000	200,000	200,000	200,000	-	800,000	49
		Upgrade Breakers at Scriba	C28708	2,000,000	1,500,000	-	-	-	3,500,000	40
		Upgrade Breakers at Volney	C33252	2,000,000	500,000	-	-	-	2,500,000	49
		Upgrade Niagara-Pakard #195	C29945	-	-	35,000	195,000	1,430,000	1,660,000	40
	Other System Capacity & Performance Total			**5,848,000**	**7,302,000**	**9,968,000**	**20,996,000**	**7,230,000**	**51,344,000**	
	Overhead Line Refurbishment Program	Browns Falls - Taylorville 4 Lightning Enhancements	C24359	4,550,000	-	-	-	-	4,550,000	37
		Coffeen - LH 5, T2120 Lightning Enhancement	C24360	800,000	-	-	-	-	800,000	37
	Overhead Line Refurbishment Program Total			**5,350,000**	**-**	**-**	**-**	**-**	**5,350,000**	
	Reliability Criteria Compliance	Andover Cap Bank, part of SG075	C24014	400,000	-	-	-	-	400,000	39
		Batavia Second 115kV Cap Bank, part of SG077	C31478	100,000	50,000	1,120,000	-	-	1,270,000	34
		Construct Southwest Station (Line Station), part of SG075	C24016	562,000	1,500,000	780,000	-	-	2,842,000	39
		Construct Southwest Station, part of SG075	C24015	5,000,000	18,000,000	2,000,000	-	-	25,000,000	39
		Conversion of #109 to 115kV-part of SG077	C24629	210,000	1,550,000	9,165,000	-	-	10,925,000	34
		Dunkirk Second Bus Tie- Line, part of SG075	C31460	-	55,000	110,000	1,074,000	-	1,239,000	19
		Dunkirk Second Bus Tie- Station, part of SG075	C31459	-	55,000	318,000	1,017,000	-	1,390,000	19
		Golah work for #109 Conversion - part of SG077	C24631	500,000	2,000,000	3,000,000	-	-	5,500,000	34
		Homer Hill 115kV Capacitor Banks, part of SG075	C31457	1,031,000	213,000	-	-	-	1,244,000	28
		Mortimer Work for #109 Conversion - part of SG077	C24630	260,000	1,575,000	2,125,000	-	-	3,960,000	34
		Rebuild line #181 and #180 (Station Work), part of SG075	C24019	100,000	100,000	1,500,000	1,000,000	-	2,700,000	27
		Rebuild line #181 and #180, part of SG075	C24018	1,500,000	2,000,000	13,000,000	20,000,000	18,000,000	54,500,000	27
		Reconductor portions of 54 and 181, part of SG075	C31463	-	205,000	-	-	-	205,000	19
		Reconductoring of #171, part of SG075	C24017	790,000	2,250,000	150,000	-	-	3,190,000	39
		Replace HH Ckt #157 Connections, part of SG075	C31458	63,000	6,000	-	-	-	69,000	28
		Replacement of #171 connections, part of SG075	C33884	20,000	60,000	10,000	-	-	90,000	49
		Second 115kV bus tie at Lockport, part of SG077	C31482	730,000	-	-	-	-	730,000	34
		Upgrade Batavia South 115kV busring, part of SG077	C31479	75,000	180,000	-	-	-	255,000	28
		Upgrade capabiity of L107, part of SG077	C31481	225,000	-	-	-	-	225,000	34
	Reliability Criteria Compliance Total			**11,566,000**	**29,799,000**	**33,278,000**	**23,091,000**	**18,000,000**	**115,734,000**	
	Reserve	Resreve	CNYX33	(7,800,000)	(12,200,000)	(4,500,000)	(2,900,000)	(2,000,000)	(29,400,000)	49
	Reserve Total			**(7,800,000)**	**(12,200,000)**	**(4,500,000)**	**(2,900,000)**	**(2,000,000)**	**(29,400,000)**	
System Capacity & Performance Total				**46,301,000**	**81,085,000**	**51,047,000**	**46,843,000**	**28,380,000**	**253,656,000**	
Non - Infrastructure	Other - Non Infrastructure	Asset Separation strategy	CNYAS87	-	-	-	100,000	500,000	600,000	39
		Flood mitigation	CNYAS46	-	-	2,000,000	1,000,000	-	3,000,000	22
	Other - Non Infrastructure Total			**-**	**-**	**2,000,000**	**1,100,000**	**500,000**	**3,600,000**	
	Physical Security	Physical Security Strategy	CNYAS86	100,000	6,000,000	3,000,000	-	-	9,100,000	40
	Physical Security Total			**100,000**	**6,000,000**	**3,000,000**	**-**	**-**	**9,100,000**	
Non - Infrastructure Total				**100,000**	**6,000,000**	**5,000,000**	**1,100,000**	**500,000**	**12,700,000**	
Grand Total				**132,000,000**	**228,000,000**	**290,000,000**	**295,000,000**	**295,000,000**	**1,240,000,000**	

EXHIBIT 3

PROGRAM NAME:

Northeast Region Reinforcement - (Luther Forest)

DESCRIPTION:

Reinforce the transmission system in the Northeast region due to anticipated load growth

This major program consists of reinforcements of the transmission system in the Saratoga and Glens Falls area of Eastern New York necessary to respond to reliability needs caused by area load growth and the impact of the proposed Luther Forest Technology Campus (LFTC). The timing and content of this program depends on a decision by Global Foundry ("GF") to move forward with its plans to build a new micro-chip fabrication facility. This program is expected to cost approximately $166M.

The recommended plan is made up of the following key elements:

- C18250 – Reconductor Rotterdam #1&2 Lines. Expected in service date is 06/30/2010.
- C31326 – New Turner Road 230/115kV substation in the vicinity of the location where the existing Rotterdam-Bear Swamp #E205 230kV line crosses the existing Mohican-N. Troy #3 line and the Battenkill-N. Troy #10 115kV lines. This station would serve as a primary source to those lines providing service to the east side of the 115kV northeast system. Expected in service date is 12/31/2012.
- C34523 – Replace five 115 kV North Troy breakers with 63 kA breakers for increased short circuit capability with Turner Road. Expected in service date is 12/31/2012.
- C31418 – New 115kV Rotterdam line parallel to the existing Spier Falls to Rotterdam #1&2 line circuits. This line would reinforce the west side of the 115kV system that serves the northeast. Expected in service date is 12/31/2012.
- C31419 – New taps of Rotterdam-Bear Swamp #E205, Mohican-North Toy #3 and Battenkill-North Troy #10 lines to serve new Turner Road substation. Expected in service date is 12/31/2012.
- C34528 – Rebuild/reconductor 14.2 miles of Mohican-Battenkill #15 115 kV line. Expected in service date is 12/31/2012.
- CNYX39 – Future projects which include:
  - Rotterdam new 230/115 kV transformer
  - Reactive compensation program
  - Reconductoring/rebuilding 22.9 miles of existing 115 kV lines
  - Increase conductor size from 795kcmil ACSR to 1033.5kcmil ACSR for Luther Forest direct connection

With the introduction of the GF load, The Company must expeditiously advance the proposed strategy.

DRIVER:

The transmission system which serves The Company's Northeast Region is presently exposed to post-contingency thermal overloads during summer peak periods. These violations of The Company's Transmission Planning Guide (TGP28) show inadequate thermal capacity with respect to the three Rotterdam 230-115 kV transformers and the Spier-Rotterdam #1/#2 115 kV double circuit. This shows a need to simultaneously add bulk-power transformation capacity and relieve 115 kV thermal overloads which affect the transmission supply to the Northeast Region.

The Company has worked with Luther Forest Technology Economic Development Corporation (LFTCEDC) toward developing Luther Forest Technology Campus (LFTC), which has culminated with GF's commitment to build a chip-manufacturing plant at the campus. The addition of GF and the projected load growth within the Northeast Region will exacerbate the performance issues.

Without improvements being made to the Northeast Electrical System, the development of the LFT campus could be jeopardized along with the economic benefits to the customers in the region.

Additionally, the Saratoga/Glens Falls area has been experiencing significant load growth with a growth rate of 3% annually (projected over the next 10 years). If the LFTC develops as expected, the anticipated jobs it would directly create along with ancillary jobs could increase the growth rate to 7% annually over 10 years.

While there is confidence in the projected load growth rate of 3% without the LFTC, there is a high degree of uncertainty associated with the 7% load growth projection with the LFTC. Load growth with and without the addition of LFTC is expected to exceed spare capacity within the region within a ten-year planning horizon. In order to maintain reliability of service and system performance during the next ten-year period, with the potential addition of LFTC, it's necessary to proceed with the recommended plan according to the schedule above. The inclusion of the potential provision of service for LFTC requires the recommended plan to be able to quickly accommodate a very large addition of load to the Northeast Region.

OTHER ALTERNATIVES CONSIDERED:

The main alternative to the recommended plan for resolving transmission-performance issues of the northeast region of The Company's NY service territory is the "345kV" plan. The 345kV strategy involves the addition of a 345-115kV station near South Saratoga, and reinforcement of the Spier-Rotterdam 115kV circuits between South Saratoga and Spier Falls at a cost of $242M. The recommended 230kV reinforcement plan has considerable advantages over the 345kV option in terms of cost, environmental effects, permitting, scheduling, and flexibility. It is forecasted to cost $166M.

An evaluation of the energy efficiency programs show that the magnitude of the need is beyond the demand reduction that can be obtained by energy efficiency programs.

CUSTOMER BENEFITS OF PROGRAM:

The transmission reinforcement plan will resolve thermal and voltage problems which will result from projected load growth in the Northeast Region. More specifically, the 230-115 kV transformers at Rotterdam and Spier-Rotterdam #1/#2, which are primary components of the transmission supply for the Northeast region, already may exceed their ratings for certain contingency conditions according to The Company's Transmission Planning criteria. This will worsen with time as GF is connected to the transmission system and the load grows as expected. The Company's obligation to respond to the load growth and serve its customers gives a high priority to the Northeast Region Reinforcement Plan.

Additionally, the transmission reinforcements will reduce dependence on local generation for reliability of service within the region.

METRICS TO TRACK BENEFITS:

The effectiveness of the program will be evaluated by the program's ability to correct thermal and voltage problems in the Northeast Region.

COSTS AND AVOIDED COSTS:

Expenses Associated with Program

Since this transmission reinforcement plan involves the addition of new assets, it is assumed there will not be trouble maintenance expenses for several years. So the added OPEX from this project will come from planned preventative maintenance as follows:

<u>Visual and Operational Inspections</u>

Part of the reinforcement strategy includes the construction of a new four-breaker ring 230:115 kV station near the North Troy substation to support area voltage. This new station will require visual and operational inspections on a monthly basis at an estimated cost of $400/month, which equates to $4,800/year.

<u>Mechanism Tests</u>

In total, the reinforcement strategy proposes the addition of 9 new breakers (9 – 115 kV breakers). Each one of these new breakers will require a mechanism test to be performed on a 24 month period. The estimated cost of each test is $800/test, which equated to $400/year per breaker. This will result in a total estimated expenditure of $3,600/year for all 18 breakers.

<u>Diagnostic Tests</u>

In addition to the mechanism tests, the 18 new breakers also require diagnostic tests to be performed every 108 months. The estimated cost of diagnostic test for 115 kV and 230/345 kV breakers are:[84]

- 115 kV & 63 kV: 3 Technicians/16 Hours Every 108 months – $500/yr
- 230/345 kV: 4 Technicians/16 Hours Every 108 months – $700/yr

This will result in a total estimated expenditure of $10,000/year for all 18 breakers.

Diagnostic testing will also be required for the 3 new transformers being proposed in the reinforcement strategy (230:115 kV transformers for the new station near North Troy and the 230:115 kV transformer at Rotterdam). The diagnostic test for transformers is performed every 72 months at an estimated cost of $12,000/test. This equates to an annual cost of $2,000/year per transformer or $6,000 in total.

Dissolved Gas Analysis (DGA) Tests

In addition to the diagnostic test, the 3 new transformers will also require a DGA test every 6 months. The cost of this test is estimated to be $400 each time,, which equates to an annual expenditure of $2,400.

Line Maintenance and Inspection Program

The reinforcement strategy proposes the addition of a new Spier-Rotterdam 115 kV transmission line approximately 60 circuit miles in length. These circuit miles will require the following planned line maintenance and inspection work:

- Infrared Patrols – $65/circuit mile
- Tower Painting – $2,540/structure
- Footing Inspections and Repairs – $1,760/structure
- Helicopter Patrols – $25/circuit mile
- Foot Patrols - $30/structure

The total annual cost of performing this work is estimated to be approximately $60,000/year.

Capacitor Banks

The exact timing and scope of the reactive compensation program will need to be coordinated with actual load growth, GF's schedule, and further investigation into alternate sites for capacitor additions. But in general the addition of ten 13.2 kV capacitors, three 34.5 kV capacitors, and three 115 kV capacitors with an estimated annual preventative maintenance costs of $2,600/year equate to approximately $41,600/year.

In total, the new facilities required for the northeast region reinforcement plan are estimated to add preventative maintenance expenses of approximately $130,000/ year.

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[84] Data based on The Company maintenance standards and current work practices. Labor rates based on $100/hour

EXHIBIT 4

PROGRAM NAME:

Digital Fault Recorder (DFR) Strategy – Bulk

PROGRAM DESCRIPTION:

This program will install 20 Digital Fault Recorders (DFRs) at bulk power stations due to mandatory NERC and NPCC requirements introduced in 2007. The program commenced in 2007 (based on a 2004 program) and is expected to be complete in 2011.

DRIVER(s):

According to the mandatory NERC and NPCC criteria introduced in 2007, transmission owners must monitor system conditions at all bulk power stations and have the ability to capture the monitored data should a system disturbance occur. This information is vital to the post disturbance analysis and the specific elements to be monitored are detailed in the criteria. In addition, the criteria also specify such items as the required period for keeping data, as well as the sample rate. The purpose of a DFR is to perform this capturing and storage task for detailed power system information immediately during and after a system disturbance.

The original program from 2004 was developed to address NPCC and NERC criteria that were developed in the wake of the 2003 blackout. This program called for installation or upgrade of DFRs at bulk power locations that did not have adequate data capturing capability.

In August 2007, the following mandatory criteria went into effect:

- NERC Standard PRC-002-1; Regional Disturbance Monitoring and Reporting Requirements
- NERC Standard PRC-018-1; Disturbance Monitoring Equipment Installation and Data Reporting
- NPCC Document A-15; Disturbance Monitoring Equipment Criteria for the Bulk Power System. The above two NERC standards are summarized in this document.
- NPCC Document A-10; Criteria for Bulk Power Stations

Since these criteria represented a significant change from the ones followed in 2004, the DFR program needed to be revised. Due to this, the program was revised to include eleven additions and nine replacements for a total of twenty DFR installations. This includes two non-bulk power stations that were deemed critical enough to warrant DFR installations. The five additions completed under the old program were not included in this revision.

OTHER ALTERNATIVES CONSIDERED:

Option 1 – cancel the current program

This option would involve no further installation of DFRs at bulk power stations. This option would not call for initial expenditures, however, there could be substantial penalties for non-compliance with NERC and NPCC standards.

Option 2 – Utilize existing microprocessor relay capabilities

This option would employ the waveform capture and fault analysis capabilities of modern microprocessor relay. This will require the installation of microprocessor based relays to replace the existing electromechanical relays at many of the sites.

It is a more expensive option to install a microprocessor based relay to provide fault recording capability. A typical DFR package costs approximately $35,000 and can monitor the current and voltages of up to 12 transmission lines. A microprocessor relay costs on average $7,500. Two of these are required per transmission line, bringing the cost of equipment to $15,000 (these costs only take into account equipment costs and do not include all the ancillary equipment such as test switches, terminal blocks, wire, design, and labor costs that are required for both types). Therefore, the installation of a DFR is more economical if three or more lines are being monitored. There are also other considerations that make a DFR a better option for monitoring in any transmission substation:

- DFRs capture all monitored circuits in a common time base. It is difficult to combine waveforms from different microprocessor relays on a common time base.
- DFRs can capture events over varying time frames (seconds for faults, minutes for swings, hours or days for slow disturbances). Microprocessor relays have limited storage for fault data and limited record length for fault data.
- DFRs offer higher sampling rates than microprocessor relays and can more accurately capture power system transients. DFRs are independent of protection equipment and therefore are suitable for determining root causes of relay mis-operations.
- DFRs can be upgraded to Phasor Measurement Units (PMUs) by a simple software upgrade if the capability is required in the future.

Option 3 (Recommended) – Continue with the installation of DFR units at bulk sites

This recommended option will complete the remaining installations. It will address information deficiencies during system events, improve post fault analysis and improve reliability (both SAIDI and CAIDI) by identifying the cause of currently ‘unknown’ outages.

Better fault data will reduce the amount of overhead lines needed to be patrolled following faults, thereby avoiding the costs associated with helicopter and foot patrols.

CUSTOMER BENEFIT(s) OF PROGRAM:

By providing information that will improve post fault analyses, we can better identify and address issues causing the interruptions and therefore develop comprehensive strategies to improve reliability performance.

Digital fault recorders are able to calculate distance-to–fault data providing information directly into energy management systems. This information can be used instantly to detect fault locations, decreasing return-to-service times.

METRICS TO TRACK BENEFIT(s):

The Digital Fault Recorder installation program offers The Company the opportunity to improve the reliability performance of the transmission network. Reliability improvements will be measured in the following indices;

- SAIFI: System Average Interruption Frequency Index
- SAIDI: System average Interruption Duration Index
- CAIDI: Customer Average Interruption Duration Index

COSTS AND AVOIDED COSTS:

Implementing this strategy will reduce the amount of overhead lines needed to be patrolled which, in turn, reduces crew investigative costs for both preventative and troubleshooting maintenance savings.

Also, The Company will benefit by reduced financial penalties associated with poor reliability.

There will be no additional maintenance OPEX costs as a result of this program as modern digital fault recorders require no planned preventative maintenance. In some circumstances, it may be necessary to provide leased telecommunications to enable the DFR to be interrogated remotely. Generally suitable facilities are already available at substation sites.

EXHIBIT 5

PROGRAM NAME:

Conductor Clearance Correction Program

PROGRAM DESCRIPTION:

Transmission line conductor phase to ground clearance improvements

DRIVER(s):

This program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC), under which they were built, by increasing ground to conductor clearances in substandard spans. This follows standard industry practice and the Public Service Commission Order (per Case 04-M-0159 effective January 5, 2005) to adhere to the NESC.

The primary driver for this work is the initiative to ensure the safety of both the New York public and our staff as they work and travel under the overhead lines. Without this work, there remains a small, increased risk of significant safety incidents associated with overhead line clearances. The National Electric Safety Code (NESC) sets obligatory conductor clearances of overhead lines from the ground and other ground based objects. This includes transportation, ensuring the safe operation of overhead power lines, and recognizing the need to move and work safely under them.

The code was first introduced in 1914 and has since been revised significantly on a number of occasions. Since 1977, the NESC has contained a grandfathering provision providing that power lines installed in accordance with prior editions need not be modified to meet changing code requirements. For all transmission lines installed prior to 1977, the initial grandfathering provision called for compliance with the standards in effect prior to 1977. Since 1973, legal compliance has been checked against the 1973 code. If constructed after 1973, the code that was in force at the given time was followed during line constructions. The latest version of the NESC was issued in 2007.

Two basic facets of this program exist:

1. To ensure adherence to the clearance-to-ground requirements under the appropriate **governing** safety code or regulation ("codes") for existing transmission circuits. The governing code is defined by the following table:

Year Constructed	Applicable **Governing Code**
1977 or earlier	1973 NESC[85]
From 1977 to 1980	1977 NESC
From 1981 to 1983	1981 NESC
From 1984 to 1990	1987 NESC
After 1990	2007 NESC

In cases where governing code requirements are not met, line clearance rectification projects will be implemented. When structure replacements or modifications are needed, the design will meet the more stringent current code.

2. In order to enhance public safety, exceptions will be made over railroads, roads, streets, driveways, parking lots, water bodies, and clearly developed right-of-way access roads crossing under a span. These areas of exceptions will be required to meet the more stringent current code (instead of the governing code).

There are two key factors when determining the clearances to ground required by these codes: the use of the land underneath the conductors and the maximum operating temperature of the conductors. There are two primary areas of ambiguity in interpreting these drivers:

a. Land use for vehicle versus pedestrian areas.[86]

b. High conductor temperature operation.[87,88]

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[85]. National Electrical Safety Code, 1973 edition (1973 NESC)

[86] This deals with the presence of vehicles underneath the conductors. The NESC defines clearance requirements for two generally accessible areas (as opposed to railroads or bodies of water which have more limited access): areas accessible to pedestrians and areas such as streets and roads accessible to vehicles. Greater ground clearance is required in areas considered accessible to vehicles. The NESC does not define a clearance requirement for areas that are not streets but where vehicles could theoretically operate, such as open fields. Beginning in 1987 the NESC added a definition of those areas where the pedestrian-only criteria could be applied: "Spaces and ways subject to pedestrians or restricted traffic only are those areas where equestrians, vehicles, or other mobile units, exceeding 8 feet in height, are prohibited by regulation or permanent terrain configurations or are otherwise not normally encountered or not reasonably anticipated." Transmission line ground clearance requirements of the Codes differ based on vehicle accessibility below conductors. Prior to the addition of this definition, The Company and its predecessor companies frequently interpreted areas that were not roads, streets, and alleys as being areas accessible to pedestrians. The current NESC require vehicle clearances unless vehicle inaccessibility can be demonstrated.

[87] The higher the conductor temperature, the more a conductor sags - thereby reducing clearance levels with the ground. Higher loading currents increase the conductor temperature.

[88] Older NESC editions required compliance with specified minimum clearances at 120F (50C) instead of "the maximum conductor temperature for which the line is designed to operate" as stated in the current NESC edition.

For the implementation of this program, The Company's interpretation of the code clearance requirements for existing circuits is:

Year Circuit Constructed	Applicable Code	Interpretation of Land Use Ambiguity	Interpretation of Temperature Ambiguity
Prior to 1977	1973 NESC	Areas other than those normally accessible to vehicles (roads, driveways, etc.) require pedestrian only	120°F
1977 – Present	See Table	Only areas where vehicle traffic is restricted are pedestrian only	"maximum conductor temperature for which the line was designed to be operated" as stated in the NESC edition is presently interpreted by The Company as the conductor temperature at maximum emergency line rating (STE)

The need to address correct substandard clearances is not believed to be unique to New York. It appears to be present in all of the The Company companies. This is due to improvements in computational power, survey techniques, installation methods and engineering practices allowing for higher levels of accuracy than previously available.

The Aerial Laser Survey (ALS) technique is a relatively new technology. This technique uses laser pulses from a plane or helicopter to determine the relative heights of structures and wires from the ground, as well as the specific locations. ALS is much quicker than conventional ground based survey teams and has a similar level of accuracy. This technology will be used on all of the transmission circuits in New York to identify specific spans out of compliance. A prioritized risk based approach is being used to assess, and then address the issues identified. Approximately 25% of the New York network has been assessed using the ALS, and it is anticipated that the entire network will be assessed in this manner by 2011. Preliminary results of the survey to date have indicted that approximately 20-25% of the spans (based on a total of 782 spans) are currently not in compliance with the applicable code.

Using the ALS data, the phase-to-ground conductor clearances are evaluated and prioritized using a grading system, with a grading of "Level 1" being the furthest out of compliance with its governing code, "Level 3" being marginally out of compliance with its governing code, and "Level 4" being in compliance. This grading system also takes into consideration a line's recent historical loading as conductor temperature impacts clearances.

OTHER ALTERNATIVES CONSIDERED:

Option 1: Do nothing. Do nothing until a line is refurbished based on asset condition, or upgraded due to planning or regulatory requirements.

Reason for rejection: Failure of The Company to maintain clearances in accordance with the standards set in the National Electric Safety Code. Thus, The Company fails to conform to Public Service Commission Order (per Case 04-M-0159) to adhere to the NESC. A significantly higher safety risk exists at road, railway, and navigable waterways. The Company would have potential exposure to litigation and punitive actions in the event of an inadvertent contact.

Option 2: Regionalized Span Based Approach. Bring substandard spans up to code over a reasonable period of time, prioritized by risk and the ability to optimize the timeframe by splitting up work into geographical "segments." The geographical segments containing Level 1 substandard clearances would be prioritized to bring up to code first, followed by segments containing Level 2 substandard clearances (but no Level 1s), then level 3. The lines will meet the minimum governing code requirements. There would be little or no coordination with other refurbishment projects.

In all cases, the spans corrected would meet the current code requirements.

Reason for rejection: Option 2 meets our obligatory governing NESC requirements but does not provide further safety enhancements. Some cost savings might be incurred over Option 3. However, when actual modifications are needed, the cost to upgrade from the governing code to the current code over railroads, roads, streets, driveways, parking lots, water bodies, residential developments, commercial developments, and clearly developed right-of-way access roads crossings is relatively minor. Only a small percentage of spans would meet the governing code (but not the current code) for the safety upgrade "exceptions" noted in Options 3 and 4.

Option 3: Prioritized Span Based Approach. Bring substandard spans up to NESC requirements by replacement over a reasonable period of time, prioritized by risk with work bundled as appropriate, thereby reducing the overall cost of implementing the strategy. As much as practical , Level 1 spans at road crossing would be prioritized to be corrected first, followed by Level 1 spans elsewhere, followed by segments containing Level 2 spans (but no Level 1s), then Level 3s during refurbishments. In general, the lines will meet the governing code requirements.

In all cases, the spans corrected would meet the current code requirements. The remaining spans would meet the governing code in majority of the cases. The Current Code will be used over railroads, roads, streets, driveways, parking lots, water bodies, residential developments, commercial developments, and clearly developed right-of-way access roads crossing under a span.

Reason for rejection: Option 3 requires additional financial resources, more implementation time, and additional manpower resources due to the logistical challenges posed by the scattered nature of the substandard spans. Option 3 presents considerable logistical and delivery inefficiencies. This increases the overall time to accomplish the program. Thereby, it does not reduce overall risk as quickly as originally anticipated. Repeatedly taking the same line out at different times over several years, demobilizing, and remobilizing crews within the same area causes program delays and creates construction inefficiencies as well as additional crew risks and time delays.

Option 4: Prioritized Line Base Approach (Recommended Option). Replace over a reasonable period of time, prioritized by the overall cumulative risk (as much as practical) and the ability to optimize the timeframe by the bundling of work into line-by-line risk prioritization. The lines containing the highest overall Level 1 & 2 risk scores would be marked as the high priority ones. In addition, each year, about 12 of the highest risk spans on the system (throughout New York and New England) would also be targeted. Level 3 spans will be modified to meet code requirements during condition driven and planning line refurbishments.

In all cases, the spans corrected will meet the current code requirements. The remaining spans would in most cases meet the governing code. Spans meeting the governing code would be left “as is”.

Option 5: Crash Program. Conduct a crash program to correct all known substandard spans within 1-3 years.

Reason for rejection: Option 5 presents severe logistical and resource implementation problems. In addition, crash programs frequently introduce risks that are associated with doing work too hastily. A trade off then exists between the safety risks of proceeding too fast versus the risk from substandard lines that have been operated safely for years. In addition, the risks from taking so many transmission lines out in a short time period could pose other hazards and dangers to the public (for example, a local black out introduces certain risks depending on the duration and extent).

Option	Conceptual Cost Range	Comments
1	None	Potential exposure to litigation and punitive actions in the event of an electrocution
2	About 5% less than Option 3	Segmentation offers some improvements in construction efficiency over option 4
3	$160 million	Due to increased mobilization costs over Option 4
4	$120 million	
5	Not determined	

CUSTOMER BENEFIT(s) OF PROGRAM:

While safety events caused by substandard clearance conductors are extremely rare, the consequences of such an event would be extremely serious. Since it is possible to minimize the risk from undesired conductor contact through adherence to the NESC, it is entirely appropriate that the network be assessed, and steps be taken to ensure that the transmission assets in New York meet this standard (using a prioritized approach to ensure that the most critical issues are addressed first).

METRICS TO TRACK BENEFIT(s):

Future ALS data should show adherence to the governing NESC codes. The number of substandard spans will be reduced and eventually eliminated.

The safety benefits are difficult to measure as safety events associated with clearances are extremely rare and therefore difficult to analyze or to provide trend analysis for. However, while it is not easily measurable, the program will result in a reduction in the "risk" of an extremely serious safety event, in accordance with the safety design guidelines of the NESC standards.

COSTS AND AVOIDED COSTS:

The scope of this program was developed with consideration of the overall risks to public safety and the obligatory nature of the code requirements[89]. A prioritization criterion was used to identify clearance profiles that optimize the costs and benefits to customers.

The scope of work can be defined as a correction of identified spans in a prioritized manner over a reasonable timeframe. The prioritization process is focused on enhancing public safety. Targeted work is then bundled by geographic areas[90], ensuring efficient delivery of the overall program.

Given the volumes of work anticipated and the risk to public safety posed by each prioritization level, the following time periods are recommended to rectify the potential non-compliance:

Level	Time Period	Justification
1	<3 years	Allows 1 year for project approval, engineering, and 2 construction seasons to rectify, to ensure outage availability. The "clock" starts once identified by ALS.
2	<5 years	Allows 2 additional outage seasons to rectify based on additional span volumes and outage availability. Again, the "clock" starts once identified by ALS.

[89] Hannigan, J.F., Gillis, L.R., and Peterson, A. J. Strategy SG029, **Transmission Line Ground Clearance Improvements**, The Company Transmission, 19 March 2007. (Capital Investment Plan, Exhibit 18.A and 18.C)
[90] This will be determined on a case by case basis following preliminary engineering, but when possible individual transmission lines (or significant pieces of them) will be defined as a geographical area.

3	**~20 years**	Spans present minimal public safety risk. Most economic approach is to rectify remaining low risk substandard line clearances at the next time the circuit is being worked on.

The above time line provides the suggested guidelines for implementing this approach in New York. The final implementation priority and schedule will be determined after completing preliminary engineering on each line. This will need to take into account risks, implementation logistics, outage planning, system security, and reliability impacts.

When bundling the work with other projects or strategies it is the intent of this program to bring all spans that require a structure replacement into compliance with the present NESC code. It shall be accomplished using the following guide lines:

- Clearance only projects will address only the spans requiring change.
- Minor refurbishment projects will address only those spans affected by the project. An example of this would be pole replacements.
- Major refurbishments would require all spans in the project area to be brought to current code. An example of this would be a rebuild of a section of line. Capacity addition, or thermal upgrade projects, would also require all spans to be accordance with the current code. The same would be true for new line projects.

Planned expenditures for this major program are described below. However, the program is expected to continue for approximately the next 20 years.

Conductor clearance refurbishment (CCR) projects will be set up for candidate lines with the highest overall cumulative risk scores. In some cases (for abnormally high outlier risk span), individual spans projects will be set up. During these CCR projects, Level 1 and 2 spans will be brought up to code as part of the conductor clearance strategy. In other cases, conductor clearance work may be bundled into an existing project for efficiency. Level 3 substandard spans will be corrected under the systematic, long-term, Overhead Line Refurbishment strategy (SG080). Funding Order C03256 was approved to address certain substandard spans. This funding order now serves as a placeholder until project scopes and conceptual estimates are identified.

Below is a list of the CCR projects initiated as a result of the Conductor Clearance Strategy (SG029 Version 3). The project scopes, estimated costs, and construction schedules are being now being developed. As safety is the primary driver, no significant avoided costs are expected. However, avoided litigation costs could be on the order of $1 – 10 million.

Project Number	**Driver or Strategy**	**Title**
C31129	SG029	Adirondack-Porter 12 T4010 CCR
C31130	SG029	Adiron-Chase-Porter T6340-T6350 CCR
C31131	SG029	Rotterdam-Altamont 17 T5620 CCR
C31132	SG029	Greenbush-Stephentown 993 T5190 CCR
C31134	SG029	Meco-Rotterdam 10 T5390 CCR

C31135	SG029	Mortimer-Elbridge 2 T1570 CCR
C31136	SG029	Volney-Clay 6 T2720 CCR
C31137	SG029	Nine Mile One-Clay 8 T2350 CCR
C31138	SG029	Scriba-Volney 20 T2540 CCR
C31141	SG029	Oswego-LaFayette 17 T2420 CCR
C31145	SG029	Hudson-Pleasant Valley 12 T5230 CCR
C31146	SG029	Mortimer-Quaker 23 T1610 CCR
C31147	SG029	Clay-Teall 10 T2090 CCR
C31148	SG029	Mortimer-Pannell T1590-T1600 CCR
C31149	SG029	Lockport-Batavia 107 T1490 CCR
C31150	SG029	Mortimer-Golah 110 T1580 CCR
C31151	SG029	Niagara-Lockport 101 T1690 CCR
C31152	SG029	Niagara-Lockport 102 T1700 CCR
C31153	SG029	Gardenville-Dunkirk T1240-T1250 CCR
C31154	SG029	Packard-Huntley 130 T1820 CCR
C31155	SG029	Gardenville-Buf Rvr T1210-T1220 CCR
C31156	SG029	Huntley-Gardenville T1400-T1410 CCR

The OPEX savings from the replacement of towers to meet conductor clearances are mainly anticipated to come from decreased planned preventive maintenance.

At this point the anticipated savings are conceptual in nature, and stem from typical savings over the next 4 years.

Reduction in Trouble Maintenance

No significant reductions in trouble calls are anticipated.

Decreased Planned Preventive Maintenance

The number of substandard spans in New England was estimated to be approximately 4,000 prior to all the recent refurbishments (SG029 Version 2). For estimation purposes, this was doubled for New York pending a more thorough analysis by Transmission Line Engineering. The average cost for correcting a substandard span in New York was assumed to be $25,000.

Assuming 50% of spans require a structure replacement, or approximately 4,000. Of these, the following assumptions are made:

- 30% are Level 1 (approximately 1,200 structures)
- 30% are Level 2 (approximately 1,200 structures)

- 40% are Level 3 (approximately 2,400 structures)

Based upon the Transmission GIS, there are 38,003 structures in New York:

- Steel Structures (pole) – 7.3% (or 2,783 structures)
- Steel Towers – 45.9% (or 17,448 structures)
- Wood Structures – 46.8% (or 17,772 structures)

Level 3 spans will be corrected as part of long-term refurbishment projects – none expected to be replaced through this program.

Assume the correction of Level 1s and 2s over the next 12 years (starting in FY2010/11) per timeline in SG029 Version 3, or approximately 2,500 structures are replaced during this period. Over the next 12 years, the average replaced would be approximately 210 per year.

Initial annual population of 210 structures:

- Steel Pole & Tower Structures 53.2% or approximately 110 structures
- Wood Pole Structures 46.8% or approximately 100 structures

An initial savings on painting, footer inspection & repairs, and ground-line treatment is expected. Consistent with paragraph 19 in Strategy SG052, approved on 24 Feb 2006, the new steel structures will not be painted or the footers repaired during the first painting and footer inspection & repair cycle after installation. However, this will most likely occur in the following 20-year cycle. Ground-line inspections and treatments generally do not occur for the first 20 years.

Painting

Steel Poles & Towers: 110 per year

Projected Savings: 110 × \$2,600 ≈ \$300,000 (15 year interim cycle)

Average annual savings: \$20,000

Footer Inspections & Repairs

Steel Poles & Towers: 110 per year

Projected Savings: 110 × \$1,800 ≈ \$200,000 (20 year cycle)

Average annual savings: \$10,000

Ground-line Inspection & Treatment

Wood structures: 100 per year

Projected Savings: 100 × \$250 ≈ 25,000(10 year cycle)

Average annual savings: \$2,500

The Company reinstated the painting program after the acquisition of Niagara Mohawk. This OPEX program had been discontinued by Niagara Mohawk for a number of years prior to the acquisition. Consequently, these savings <u>are</u> <u>not</u> included. The footer inspection & repair as well as the ground-line inspection and treatment programs did exist at the time of the acquisition. These savings <u>are</u> included below for an OPEX savings of 12,500 the first year and incrementally increasing thereafter.

The average incremental maintenance spending over the next 4 years is reduced by:

FY2010/11	FY2011/12	FY2012/13	FY2013/14
\$12,500	\$25,000	\$37,500	\$50,000

EXHIBIT 6

PROGRAM NAME:

RTU Replacement Strategy

PROGRAM DESCRIPTION:

Replacement of Remote Terminal Units

The scope of this program includes:

- Replacement of 123 transmission RTUs. These are located at both The Company owned stations as well as those owned by neighboring utilities and generating stations.
- Procurement of test equipment to adequately maintain the new RTUs.

This program began in 2004 with the first RTUs going in service in 2005. It is anticipated the program will be complete by 2013.

Replacements will be prioritized in an effort to assure reliability and to minimize cost. Priority will be determined by the following:

- Bulk power status.
- Stations where the current RTU has operational or maintenance issues.
- Stations with ongoing/upcoming construction.

DRIVER(s):

The purpose of an RTU is the gathering of inputs from a remote location, such as breaker open/close status, transformer/line loading & alarming, and transmitting it to a computer at a system control center. An RTU also can take control commands from the control center and transmit them to a remote location. This allows control center operators to evaluate conditions at remote locations as well as operate devices remotely. This RTU-control center combination is commonly referred to as a supervisory control and data acquisition, or SCADA system.

RTUs perform critical monitoring of power systems and alert system operators of outages and other problems with the system. This allows for a more timely effort to fix problems and restore equipment should an event occur, thus increasing reliability. RTUs also perform critical monitoring of equipment such as breakers and transformers. Conditions such as transformer oil level are monitored to alert operators that a release may be occurring, allowing a timely response to leaks.

In the 1980s, Niagara Mohawk embarked on a plan to replace its one-on-one master and remote supervisory control system with a state of the art SCADA system (now referred to as the Energy Management System). From this plan, we now have three regional control centers located in Buffalo, Syracuse, and Albany. Additionally, a Transmission System Control Center is located in Syracuse. In order to provide data to these control centers via the SCADA/EMS system, RTUs were installed at locations throughout the system. These locations include all substations having a bus voltage of 23kV or above, generating stations, and stations owned by neighboring utilities that connect to our system. Prior to this initial installation, there were no RTUs of this kind installed on the system.

Since the original installation, several different versions of RTUs were installed. There are currently about 153 operating RTUs under The Company's control in New York. In some cases, depending on station size, more than one RTU has been installed at the same location.

The RTUs are being replaced under this major program for the following reasons:

- These RTUs and equipment are obsolete and in most cases no longer supported by the manufacturer. Replacement parts are either difficult to obtain or unavailable.[91] Failure of the RTU may be unrepairable, requiring a complete unplanned replacement on short notice. This situation could occur when data from this RTU is most critical, such as during system events, resulting in a negative reliability impact.
- Test equipment is obsolete and cannot be readily obtained or maintained. The PC based test sets still being used for maintenance were acquired in the early 1990s and use a DOS software platform. Both the RTUs and test sets utilize the M9000s communication protocol. This protocol is the legacy protocol of the original EMS and cannot be upgraded.
- These RTUs are not suitable for future integration of new substation devices and technology. The equipment does not have and cannot be modified to provide the capabilities required for modern supervisory control and data acquisition.[92] This type of functionality is becoming standard to meet current reliability needs.
- These RTUs are not compatible with the planned EMS system replacement.
- These RTUs do not meet the criteria outlined in NERC Recommendation 28, which was issued in April, 2004. This places the company at risk for not being able to provide synchronized system data during a system emergency.[93]

[91] SG002 – Revised Asset Replacement Strategy for RTUs, October 31, 2005 (Capital Investment Plan, Exhibit 20.A)
[92] SG002 – Revised Asset Replacement Strategy for RTUs, October 31, 2005 (Capital Investment Plan, Exhibit 20.A)
[93] North American Electric Reliability Council (NERC) "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April 5, 2004 Page-162

ALTERNATIVES CONSIDERED:

Option 1 – Planned Replacement. RTUs need to be replaced to maintain or improve the reliability performance and operation of The Company's system.

Option 2 – Modify Existing RTUs. Existing RTUs do not support the latest protocols necessary to communicate with a new EMS system. Without replacing these RTUs, modifications would need to be made, enabling communication with a new system.

Option 3: Do Nothing. Adopting this approach would require modification of the RTUs as mentioned above. It would also lead to reduced reliability since continuous repairs of existing units would at a certain point not be possible any longer. The resulting RTU replacement would take a considerable amount of time.

Option 4: Defer the replacement. This approach would require modification of the RTUs as mentioned above.

Because the existing RTUs are obsolete and in most cases not supported by manufactures as time goes on and failures inevitably occur, information will not be available to system operators. Failure to move forward with the RTU Replacement Program can increase the risk of equipment failures resulting in an extended loss of substation remote control capability and loss of elements of situational awareness.

The replacement RTUs provide up-to-date technology that meets NERC Recommendation 9 with regard to time synchronization standards and sequence-of-events recording for bulk power transmission facilities. Failure to upgrade the RTUs would put the Company in a non-compliance position with NERC.

CUSTOMER BENEFIT(s) OF PROGRAM:

Replacement of existing RTUs will improve reliability, reduce the risk of loss of substation "visibility", and ensure the provision of adequate information during a system emergency or widespread area blackout.

Customers will benefit from the improved reliability of the transmission system as well as the more efficient management of the grid. The new RTUs will provide quicker and more reliable data than their predecessors. In the event of a minor or major system disturbance, accurate data that is received in a timely manner is a necessity in the restoration process. Data received from the new RTUs will quickly identify key devices that have failed or have been affected by the event. The data will expedite isolation of the problem, reduce the duration of the outage and in some cases avoid expansion of the outage to other system components.

Furthermore, if obsolete RTUs are not replaced, they will not be able to communicate with the new Energy Management System which would then not allow for the required modern supervisory control and data acquisition of the NY Transmission system. This type of functionality is becoming standard to meet current reliability needs.

METRICS TO TRACK BENEFIT(s):

The success of this project will be measured by the lack of obsolete RTUs on the NY Transmission system and reduced outage durations due to faster response time associated with digital technology for modern RTUs.

COSTS AND AVOIDED COSTS:

There will be no additional maintenance OPEX costs as a result of this program as modern digital RTUs require no planned preventative maintenance. In some circumstances, it may be necessary to provide leased telecommunications to allow the RTU to be fully functional with the energy management system.

EXHIBIT 7

PROGRAM NAME:

New York Inspection Projects - Capital Related Work

PROGRAM DESCRIPTION:

Replace damaged and failed transmission overhead line components identified during field inspections (five year foot patrols, infrared inspections, helicopter surveys, etc).

DRIVER(s):

This program assures that The Company transmission lines both steel tower and wood pole meet the governing National Electric Safety Code (NESC) under which they were built by replacing hardware, wood poles, and structure components that no longer meet the governing code requirements. This follows standard industry practice and the Public Service Commission Order per Case 04-M-0159 effective January 5, 2005 to adhere to the NESC.

The goal of this program is to replace those damaged or failed components on the transmission overhead line system identified during field inspections (five year foot patrols, infrared inspections, etc.).

For the majority of situations, components no longer meet the NESC code and may even pose an imminent safety hazard.

OTHER ALTERNATIVES CONSIDERED:

<u>Option 1: do nothing</u>. Do nothing, replace when the line is refurbished or structure failures occur.

<u>Reason for rejection</u>: Failure of The Company to maintain structures in accordance with the standards set in the National Electric Safety Code. Thus, The Company fails to conform to Public Service Commission Order per Case 04-M-0159 to adhere to the NESC. A significantly higher safety risk exists at road, railway, and navigable waterways. In addition, reliability declines could occur over time.

<u>Option 2 (Recommended Approach): Replace all damaged or failed components as identified</u>. Replace damaged components as they are identified by field inspections in accordance with the priority code assigned to it. Engineering review would be requested for more significant change-outs (i.e., replacement of a structure) that are not Priority Code 1 (immediate need).

Option 3: <u>Replace all damaged or failed components without engineering review</u>. Going forward, replace damaged component as they are identified by field inspections in

accordance with the priority code assigned to it. Replace all components in-kind, including major change-outs.

Reason for rejection: Engineering review allows for the identification of the root causes of the component's failure. For example, an improved structural design might help to prevent a repeated occurrence of the same failure.

CUSTOMER BENEFIT(s) OF PROGRAM:

Maintenance of the appropriate public safety level by assuring that damaged or failed Transmission components are replaced and that all components continue to meet the governing National Electric Safety Code under which they were built.

METRICS TO TRACK BENEFIT(s):

Computapole, the Company's inspection database system, will be used to monitor the completion of Category 1 (codes 1 through 4 are observed by field inspectors and logged into Computapole during the inspection process). In addition, Category Codes 2 (completion within six months) and 3 (completion within approximately two years) can be monitored to determine how quickly identified problems are addressed.

COSTS AND AVOIDED COSTS:

Funding project, C26923, exists to address the replacement of damaged or failed components when identified through the five year Computapole inspection process. The program will remain in place and no reduction in the OPEX program is expected as a result of this program. These inspections will continue to result in new capital and operational related expenditures as the damage/failure components are discovered in the field.

EXHIBIT 8

PROGRAM NAME:

Wood Pole Management Strategy

PROGRAM DESCRIPTION:

Replace Transmission Poles Rejected During Field Inspections

DRIVER(s):

This program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built by replacing wood poles and structures that no longer meet the governing code requirements. This follows standard industry practice and the Public Service Commission Order per Case 04-M-0159 effective January 5, 2005 to adhere to the NESC.

The goal of this strategy is to replace those wood poles that have been "rejected" during the ground line inspection process. These poles are deemed to be beyond restoration by either re-treatment or placement of some form of additional pole support, usually at the ground line. Similarly, "reject equivalent" refers to deteriorated wood poles from such things as wood pecker damage, insect damage, or rotting. The following structural characteristics generally exist for these classifications:

- "Rejected" or "reject equivalent" wood poles initially designed to meet the minimum requirements in the National Electric Safety Code fail to meet code requirements for extreme design conditions. Typically, a "reject" pole has two-thirds, or less, of its original design strength.
- "Priority reject" or "priority reject equivalent" poles fail to meet National Electric Safety Code requirements and potentially can fail under conditions considered to be "normal" circumstances. The residual strength of a "priority reject" pole can fall below one-third of its original design strength.

For the majority of situations, reject and priority reject poles do not meet the NESC code. In a limited number of cases when an extra margin of safety was added into the design, some of this margin may still be available before failing to meet the code. However, this usually provides a limited amount of extra time to replace the damaged or deteriorated wood pole(s) or structures. Rarely could the pole, or structure, remain in place for a significant amount of time.

Generally, when one pole on a structure is identified as a priority reject or reject, the entire structure is changed-out. This assures that crews will not unnecessarily have to come back to replace other components of the structure in the near future. However, when it makes more sense to replace only part of the wood pole structure, the appropriate engineering solution will be followed. For example, when replacing reject poles on relatively new structure or when the adjacent pole on the structure has been recently replaced.

OTHER ALTERNATIVES CONSIDERED:

Option 1: do nothing. Do nothing, replace when the line is refurbished or structure failures occur.

Reason for rejection: Failure of The Company to maintain structures in accordance with the standards set in the National Electric Safety Code. Thus, The Company fails to conform to Public Service Commission Order per Case 04-M-0159 to adhere to the NESC. A significantly higher safety risk exists at road, railway, and navigable waterways. In addition, reliability declines could occur over time.

Option 2: replace reject and priority rejects as identified going forward. Going forward, replace priority rejects and poles (and if appropriate the entire structure) with severe damage within 6 months of being identified depending upon the severity of damage, location, and time of year. Rejects and "reject equivalent" woodpecker damaged structures within 2 years of being reported. Ignore any previous backlogs.

Reason for rejection: Historical ground line reject data provides important structural information that should be acted upon. Ignoring this data could decrease system reliability. Some reject and priority structures could remain in the field for nearly 15 years. These structures pose a safety risk, especially at road, railway, and navigable waterways.

Option 3: replace reject and priority rejects as identified and systematically work to replace the existing backlog. Going forward, replace priority rejects and poles (and if appropriate the entire structure) with severe damage within 6 months of being identified, depending upon the severity of damage, location, and time of year. Replace rejects and "reject equivalent" woodpecker damaged structures within 2 years of being reported.

CUSTOMER BENEFIT(s) OF PROGRAM:

Maintenance of appropriate public safety level by assuring that Transmission wood structures continue to meet the governing National Electric Safety Code under which they were built.

METRICS TO TRACK BENEFIT(s):

The Company maintains the wood pole structures in accordance with the governing NESC requirements. The resulting backlog of reject and priority reject poles will be kept to a minimal level.

COSTS AND AVOIDED COSTS:

Funding project C11640 exists to address the replacement of "reject" and "priority reject" poles and structures. In addition, some of this work is done through C26923 when identified through the five year Computapole inspection process.

The OPEX savings from the initiation of the Wood Pole Management Program is anticipated to come from decreased planned preventive maintenance. No significant reductions in trouble calls are anticipated. At this point the anticipated savings are **conceptual** in nature. This analysis looks at the typical savings over the next 5 years.

Decreased Planned Preventive Maintenance

An initial savings on ground-line treatment is expected. Ground-line inspections and treatments generally do not occur for the first 20 years.

	Per Structure	Current Cycle (years)	Annual Ave. Per Structure
Ground	$250	10	$25

Based upon the projections of the Wood Pole Strategy[94] about 60 structures will be replaced each year, the following structures will need replacement along with the savings:

	Fiscal Year	Wood Pole Structures	Ground-line Inspections and Treatments
1	FY2010/11	60	1,500
2	FY2011/12	60	3,000
3	FY2012/13	60	4,500
4	FY2013/14	60	6,000
5	FY2014/15	60	7,500

Woodpecker damage number were not included in this analysis as they randomly hit new and older wood poles – so an OPEX savings can not be assured. Insect damage has not been significant under C11640 – though this may change in the future.

The average incremental maintenance spending this fiscal year and over the next 4 years is reduced by:

	FY2010/11	FY2011/12	FY2012/13	FY2013/14	FY2014/15
Total (Approx.)	$1,500	$3,000	$4,500	$6,000	$7,500

[94] SG009 Version 2.

EXHIBIT 9

PROGRAM NAME:

Frontier Region Strategy

PROGRAM DESCRIPTION:

This program justification discusses a major reinforcement of the transmission system in Western NY near the existing Huntley Station. The Frontier Region 115 kV system improvements are necessary in order to respond to a reliability need caused by the retirement of generation at Huntley. Without this major program, the 115 kV system will be exposed to unacceptably low voltage levels and thermal overloads during contingency conditions.

The scope of this program was developed taking into consideration the overall risks to both reliability and system security. Based on a thorough system planning process[95], projects that optimize the benefits and costs to customers have been developed.

The project scope includes the following:

- Temporary installation of two 52.5 MVAR portable capacitor banks on the 115 kV bus at Huntley Station. Operational June 2007[96] (C30146).
- Replacement of eleven 115 kV breakers at Packard Station to allow the 115 kV bus tie at Packard to be operated closed. Planned for Completion in January 2010, however, due to fault level concerns at Niagara Station, the tie will remain open until April 2012 (C11603).
- Construction of a Gas Insulated 115 kV breaker and a half station (23 breakers) to be known as Tonawanda Station. Planned for Completion in April 2012 (C11494 and C11495).
- Installation of two 115 kV capacitor banks at the new station. Planned for Completion in April 2012.
- Retirement of the Huntley 115 kV switchyard and the removal of the relays and controls from NRG's property. Planned for Completion in 2013.
- Removal of approximately 20 miles of double circuit transmission towers between Tonawanda Station and Huntley Station. Planned for Completion in 2014.
- Construction of a control house on The Company property at Huntley for 230 kV protection, control and communications systems. Planned for Completion in 2014. (C11496).

[95] Review of the area problems, options and recommended corrective measures are documented in Frontier Area Reinforcement Study, October 2006, by Jeffery Maher

[96] In June 2007, the Company installed two temporary 52.5 MVAR portable capacitor banks on the 115 kV bus at Huntley Station. Those facilities will be available for use elsewhere on the system once the future improvements described above are made.

DRIVER(s):

Prior to its merger with The Company, Niagara Mohawk completed the sale of its Huntley coal fired generating station to NRG Energy. At that time, Huntley had six operating units, two connected to the 230 kV System and four connected to the 115 kV System (# 63, 64, 65 and 66). The emission requirements placed on the NRG facility by the Department of Environmental Conservation in 2005 resulted in NRG's decision to retire the 115 kV connected units to meet its obligation. The first two units were closed in January 2007, while the second two units were closed in June 2007.

When The Company was first notified of the planned 115 kV generation shutdown by NRG in January 2005, we immediately commenced the planning process to mitigate the effects of the loss of this crucial generation source. Studies of the area confirmed that thermal and voltage problems were present. These studies only corroborate years of actual operating experience, which demonstrated how critical these units were to supporting the area's voltage and thermal performance.

The Huntley area is supplied by three pairs of circuits: two from Packard, two from Lockport and two from Gardenville. The largest impact on the area occurs for multiple element outages, such as bus faults or faults with stuck breakers at Packard, Lockport or Gardenville, as well as double circuit tower outages of any of the circuit pairs. As these contingencies affect multiple sources in the area, the loading on the remaining sources can surpass the emergency capability of the equipment. For example, the loss of the two Packard – Huntley circuits results in overloads on the Lockport – Huntley circuits.

Outages of multiple elements also have a severe impact on the voltages at Huntley and at the customer stations supplied from radial lines #46 and #47. Some outages were so severe that the voltage was falling to 80% of nominal, which is 10% below criteria and over a 15% drop from the pre-contingency value.

With the unanticipated June 2007 retirement of the last 115 kV unit, the region required immediate capacitive support to maintain a minimum level of service. Studies showed that the voltage at the customer stations on lines #46 and #47 would be nearly 90% of nominal with all lines in service. This is below the acceptable limit of 95%. This immediate support is being provided on a temporary basis by the installation of two 52.5 MVAR portable capacitor banks on the 115 kV bus at Huntley Station. These capacitor banks bring the pre-contingency voltages above the 95% threshold, but do not correct all post-contingency voltage concerns. They are also not able to correct all of the thermal overloads. Further system reinforcement was found to be required to address these remaining problems.

Given present system conditions and minor load growth expectations, thermal support and further voltage support is needed before the summer of 2012 in order to prevent undesirable system conditions. This date is a delay from the originally requested date of 2010. It is attributed to reduced electric demand in the area surrounding Huntley station. Prior to 2012, the capacitor banks installed at Huntley will mitigate most post-contingency system concerns. However, should a severe fault occur during a heavy load period, load shedding would likely be required to maintain the security of the transmission system.

To meet the reliability need, the plan calls for construction of a 115 kV breaker and half station to be known as Tonawanda Station (formally referred to as Paradise Station), which will replace the existing Huntley 115 kV Station. This new station will include several 115 kV circuits not currently terminated at Huntley as well as capacitive support. The new station will be a Gas Insulated Station (GIS). The decision to build a GIS was driven by property constraints and careful comparison of Air Insulated and Gas Insulated station costs.

The construction of this station would create additional thermal overloads on the circuits between the Niagara/Packard area and Tonawanda station. To prevent these overloads, the normally open bus tie breaker at Packard would have to be changed to normally closed. This change would result in fault levels at Packard surpassing the interrupting capability of existing breakers. In order to allow a change in operating status (from normally open to normally closed), eleven breakers would have to be replaced. This work is nearly complete, however the bus tie at Packard will remain open until a New York Power Authority (NYPA) project to replace breakers at Niagara Station is complete in 2012. The NYPA project is also driven by the increased fault levels created by the closure of the Packard bus tie. Because the NYPA replacement is driven by a The Company system change, The Company is assisting NYPA with the up-front cost. The Company will own several breakers at Niagara, until NYPA is able to buy these assets back from The Company.

Once system upgrades are complete, the existing 115 kV switchyard at Huntley will be retired and the assets removed. This includes oil-filled breakers and cables within the station. Approximately 20 miles of double circuit transmission towers between Tonawanda and Huntley will also be retired by this project. The detailed removal plans for these retired in place assets will be determined once area upgrades are completed, though it is expected that the majority of these towers, conductors, and equipment at Huntley will be removed.

The final component of this program is the construction of a new control building to house the 230 kV protection and control equipment at Huntley. This component of the program is driven by the desire to physically separate The Company and NRG assets and concerns with the condition and location of assets within the NRG facility. If NRG were to pursue demolition work at its facility, The Company assets would need to be removed.

OTHER ALTERNATIVES CONSIDERED:

Several other alternatives were considered to address the retirement of the Huntley generation. These included the addition of 230/115 kV transformers and the reconfiguration of the 115 kV system at Huntley.

The initial option that was considered to reinforce the area involved adding 230/115 kV transformers at Huntley, and connecting the existing 230 kV and 115 kV buses. The primary concerns with this option were space and configuration. Huntley Station is bordered by a small boat marina to the north, the NRG facility to the south, the Niagara River to the west, and a large pond to the east. Minimal space is available for the new transformers. Also, The Company does not control access to the site. The configuration of the station and the condition of the 115 kV equipment would also create some concerns, which would need to be mitigated by rebuilding and rearranging the 115 kV station bus to a breaker and a half configuration. The space constraints would make this difficult to complete. In addition to the space and configuration concerns, the 230 kV system may have difficulty supporting the 115 kV system, as 230 kV voltage concerns already exist at Gardenville. A significant amount of load is supplied to Elm St and Sawyer Ave. from the 230 kV system near Huntley. Inclusion of the new transformers would add several hundred megawatts of additional stress to this system.

Once it was determined that the 230/115 kV transformers option would be difficult to implement, consideration was given to the reinforcement of the 115 kV System. The plan involved bringing Niagara – Gardenville #180 and Packard – Gardenville #182 in and out of Huntley, thereby creating four new lines. This option suffered from the same space and configuration concerns that surfaced in the transformer option. Additionally, the plan requires that four lines be brought in or out of Huntley. This is expected to be difficult as the right of way approaching the station is not wide enough for these new circuits. It is expected that some underground cable would be needed.

Given all of the space concerns at Huntley and the difficulty reconfiguring the existing assets, it was decided to consider alternative sites. Once the proposed site was found, the benefits of adding line #181 to the new station and reducing the length of six circuits made that option even more desirable.

CUSTOMER BENEFIT(s) OF PROGRAM:

The planned approach is designed to prevent thermal and voltage problems that will negatively affect system security and reliability in the customer load pocket formerly supported by the Huntley generation. Without reinforcing the system, if a contingency were to occur, load shedding would be required to maintain the system performance at an acceptable level. The reinforcement will support the existing loads for all outage conditions and allow for modest load growth in the near term. However, additional projects in Western NY are required to address other thermal and voltage concerns outside the Huntley pocket.

Transmission system reliability improvements will develop through the implementation of the permanent solutions. Six circuits currently terminated at Huntley will be approximately six miles shorter once terminated at Tonawanda. These six lines are Packard – Huntley #129, Walck Rd – Huntley #133, Lockport – Huntley #36 and #37, and Huntley – Gardenville #38 and #39. The Huntley – Lockport #37 circuit is 16th on the 2009 Annual Worst Circuit List (third quarter update). Line #39 is 85 on the list.

Three circuits not terminated at Huntley will be split in half resulting in six circuits terminating at Tonawanda. These three circuits are Niagara – Gardenville #180, Packard – Erie #181 and Packard – Gardenville #182. The #180 and #182 circuits are 29th and 43rd respectively on the Worst Circuit List.

The reduced length of these circuits will decrease their exposure, which is expected to result in a reliability improvement. The breaker-and-a-half station, state of the art relaying & control systems, and the elimination of a third party in the operation, maintenance and control of the station will also result in an improvement of the transmission system reliability.

In addition to the reliability improvements, the retirement of equipment at Huntley and replacement of equipment at Packard Station will eliminate many oil-filled devices from the system, thereby reducing environmental hazards, and decreasing the risk of a costly environmental event.

METRICS TO TRACK BENEFIT(s):

The effectiveness of the program will be evaluated by the program's ability to correct thermal and voltage problems in the system surrounding Huntley and Tonawanda stations.

COSTS AND AVOIDED COSTS:

The OPEX spending changes from the Frontier Reinforcement Strategy come mainly from preventative maintenance. Since the main driver for this strategy is the retirement of the Huntley 115kV generation rather than asset condition issues, there is no significant trouble maintenance component.

OPEX Changes in Planned Preventive Maintenance

The OPEX changes for this strategy come from the removal of approximately 20 miles of double circuit, and steel lattice transmission towers between the Paradise Station and Huntley Station (40 circuit miles, 120 miles of conductor). For this analysis, nothing is assumed to be retired in place, which would result in no appreciable maintenance savings. New steel and wood poles will be added, primarily at the Paradise Station, allowing for the reconfiguration of existing 115 kV circuits. The following list shows the lines involved in this reinforcement strategy, with the respective number of towers removed and poles added:

Line Name	Steel Towers Removed	Steel Poles Added	Wood Poles Added
Packard-Huntley #130 & Walck Rd-Huntley #133	19	7	0
Huntley-Lockport #36	20	7	0
Huntley-Lockport #37	3	0	0
Huntley-Gardenville #38 & #39	85	4	2
Huntley-Praxair #46	31	2	10
Huntley-Praxair #47	5	1	6
Packard-Gardenville #182	37	6	0

Packard-Urban #181	0	0	7
Niagara-Gardenville #180	6	6	18
Totals	206	33	43

Cost data is derived from O&M expenditures for line maintenance and inspection program cycles for New York:

- Infrared Patrols[97] $64/circuit-mile
- Steel Tower/Pole Painting[98] $2,529/structure
- Footing Inspections and Repairs[99] $1,760/structure
- Helicopter Patrols[100] $23/circuit-mile
- Foot Patrols[101] $32/structure
- Wood Pole Osmose Inspect[102] $131/pole

Furthermore, six (6) 230 kV LPOF cables that originally fed Huntley TB 130 and 140 will be retired in place. These oil filled underground cables required minimal preventative maintenance when they were energized, essentially requiring only a weekly oil level check. Estimated OPEX charges are as follows:

- Monthly oil level checks103 $1,200/yr

<u>OPEX Changes for Overhead Lines</u>

The following annual OPEX changes will take place when this strategy is executed:

Total OPEX reduction of approximately $57,000 for the removal of 206 steel towers, 40 circuit miles of overhead conductor and monthly oil level checks for 6 underground LPOF cables:

- Removal of Infrared Patrols[104] $900/yr OPEX reduction
- Removal of Tower & Pole Painting[105] $34,700/yr OPEX reduction

[97] Infrared patrols normally occur on a 3-yr cycle at a cost of $64/circuit mile. (40 ckt miles x $64/ckt-mi x .333 cycles per year = $850/yr).
[98] Simplifying assumption that steel towers and poles are both painted on same 15-yr cycle.
[99] Simplifying assumption that steel towers and poles are both inspected on same 20-yr cycle.
[100] Performed annually.
[101] Performed every 5 years.
[102] Performed every 10 years.
[103] (15 minute weekly oil level check x 4 weeks/month x $100/hr labor x 12 months/yr = $1,200/yr).
[104] (40 ckt miles x $64 cost /ckt-mi ÷ 3 cycles per year = $850/yr).
[105] (206 towers x $2,529 cost/tower over 15-yr cycle ÷ 15 years = $34,732/yr).

• Removal of Footing Inspections[106]	$18,100/yr	OPEX reduction
• Removal of Helicopter Patrols[107]	$900/yr	OPEX reduction
• Removal of Foot Patrols[108]	$1,300/yr	OPEX reduction
• Removal of Monthly Oil Level Checks	$1,200/yr	OPEX reduction

Total OPEX addition of approximately $200 for 33 new steel poles and 43 new wood poles:

The additional OPEX spending typical for new assets does not apply to the timeframe of this rate case filing. Pole painting, inspections and Osmose do not occur within the first 15-20 years of the new asset's life.

• Additional Steel Pole Painting	$0/yr	OPEX addition
• Additional Footing Inspections	$0/yr	OPEX addition
• Additional Foot Patrols109	$200/yr	OPEX addition
• Additional Wood Pole Osmose	$0/yr	OPEX addition

Approximate Net Reduction in OPEX: $57,000 (-$57,000 + $200)

OPEX Changes for Substation

The OPEX spending changes from the Frontier Reinforcement Strategy come mainly from preventative maintenance. Since the main driver for this strategy is the retirement of the Huntley 115kV generation and not asset condition issues, there is no significant trouble maintenance component.

Changes in Planned Preventive Maintenance

The OPEX changes for this strategy come from changes in type and quantity of equipment that will be in service as a result of this strategy. Cost data is derived from the following average annual preventative maintenance costs:[110]

• 115kV Oil Circuit Breaker (OCB)	$1,500/yr
• 115kV Gas Circuit Breaker (GCB)	$900/yr
• 115kV Motorized Disconnect (MOD)	$400/yr
• 115kV non-Motorized Disconnect (non-Mod)	$0/yr[111]
• 115kV Transformer	$900/yr

[106] (206 towers x $1,760 cost /tower over 20-yr cycle ÷ 20 years = $18,128/yr).
[107] (40 circuit miles x $23 cost /ckt-mi. = $920/yr).
[108] (206 towers x $32 cost/tower over 5-yr cycle ÷ 5 years = $1,318/yr).
[109] (33 steel poles x $32 cost/tower over 5-yr cycle ÷ 5 years = $211/yr).
[110] Data based on The Company maintenance standards and current work practices. Labor rates based on $100/hour
[111] There is no scheduled annual maintenance for non-motorized disconnect switches.

- 115kV Capacitor Bank $2,600/yr
- Battery Bank $800/yr

The following equipment changes will take place when this strategy is executed:[112]

Huntley – Total OPEX reduction of $37,000

- Removal of 17 115kV OCBs $25,500/yr OPEX reduction
- Removal of 9 115kV MODs $3,600/yr OPEX reduction
- Removal of TB120 Transformer $900/yr OPEX reduction
- Removal of 2 Capacitor Banks $5,200/yr OPEX reduction
- Removal of 2 115kV GCBs $1,800/yr OPEX reduction
- Removal of 34 115 kV non-MODs $ 0/yr OPEX reduction

Packard – Total OPEX reduction of $7,200

- Addition of 12 115kV GCBs $10,800/yr OPEX addition
- Removal of 12 115kV OCBs $18,000/yr OPEX reduction

Paradise – Total OPEX addition of $27,500

- Addition of 23 115kV GCBs $20,700/yr OPEX addition
- Addition of 2 Capacitor Banks $5,200/yr OPEX addition
- Addition of 2 Battery Banks $1,600/yr OPEX addition
- Addition of 58 115 kV non-MODs $ 0/yr OPEX

Net Reduction in OPEX: $16,700 (-$37,000 - $7,200 + $27,500)

OPEX Savings Conclusion

The net OPEX reduction from changes in planned preventive maintenance both from Overhead Lines and Substations savings is expected to be about $74,000/year.

The total OPEX savings is expected to be realized once all the projects associated with the Frontier Reinforcement Strategy are completed.

[112] These are only the actual net changes in equipment. Common items such as V&O inspections that will cancel out were not included.

EXHIBIT 10

PROGRAM NAME:

Reliability Criteria Compliance Western NY

PROGRAM DESCRIPTION:

This program justification discusses the major program reinforcement of the transmission system in western NY including the Frontier, Southwest and Genesee regions. This reinforcement program is needed to insure conformance to applicable reliability standards[113] out through the year 2018. Without this major program, the transmission system will be exposed to unacceptably low voltages and thermal overloads during contingency conditions. The scope of this program was developed taking into consideration both the system planning reliability requirements and the overall risks to system reliability. Based on a thorough system planning process[114], projects that optimize the benefits and costs to customers have been developed.

The program scope includes the following[115]:
Frontier Region

- Reconductor 0.3 miles of the Gardenville – Erie 115 kV circuit #54 due to thermal overloads, **Planned for Completion in Spring 2012**. (C31463)
- Rebuild 27 miles of double circuit 115 kV transmission line between Packard, Paradise and Gardenville correcting overloads, **Planned for Completion in Spring 2014**. (C24018 and C24019)

Southwest Region

- Installation of a 15 MVAR capacitor bank at Andover to boost area voltage, **Planned for Completion in Spring 2010**. (C24014)
- Construction of a new 345:115 kV station near Homer Hill station tying into Homer City – Stolle 345 kV line #37 and Gardenville – Homer Hill 115 kV lines #151 and #152 to support area voltage, the 115 kV station will include a 25 MVAR capacitor bank, **Planned for Completion in Spring 2012**. (C24015 and C24016)
- Reconductoring 6 miles of Falconer – Warren 115 kV #171, including terminal equipment at Falconer and Warren, prevent the circuit from being opened by First

[113] NERC TPL Standards, NPCC Document A-2, NYSRC Reliability Rules and the The Company Transmission Planning Guide (TGP 28). These standards require the entire transmission system to meet N-0 and N-1 voltage, thermal and stability criteria and the bulk power system and long lead time items to meet the same criteria for N-1-1 conditions.
[114] Initial review of the area problems, options and recommended corrective measures are documented in Genesee Area Review, September 2007, by Jeffery Maher and Western Division Area Review, September 2007, by Jeffery Maher. These studies were then updated in 2008, which is documented in Genesee Area Review, January 2009, by Jeffery Maher and Western Division Area Review, October 2008, by Jeffery Maher.
[115] These projects are approved in SG075, SG075v2, SG077, SG077v2 and SG077v3.

Energy due to loading concerns, **Planned for Completion in Spring 2012**. (C24017 and C33884)

- Replacement of thermally limiting connections on the Homer Hill – Andover 115 kV circuit #157 to correct overloads, **Planned for Completion in Spring 2012**. (C31458)
- Changing the operation of the Homer Hill – Andover 115kV, #157 circuit between the The Company and NYSEG systems to "Normally Closed", to boosting area voltage, **Planned for Completion in Spring 2012**.
- Installing a second 25 MVAR capacitor bank at Homer Hill to boost area voltage, **Planned for Completion in Spring 2012**. (C31457)
- Adding a second 115 kV bus tie in series with the existing bus tie at Dunkirk to correct voltage concerns, **Planned for Completion in Spring 2014**. (C31459 and C31460)
- Improving of the power factor at several 115 kV connected distribution stations between Dunkirk and Falconer to boost area voltage, **Planned for Completion in Spring 2014**.

Genesee Region

- Installing a second 25 MVAR capacitor bank at Batavia to boost area voltage, **Planned for Completion in Spring 2012**. (C31478)
- Replace thermally limiting bus conductor at Batavia to correct thermal overloads, **Planned for Completion in Spring 2012**. (C31479)
- Increasing thermal capability of #107 by replacing 0.03 miles of conductor and a CT/Relay replacement to correct overloads, **Planned for Completion in Spring 2012**. (C31480 and C31481)
- Adding a second 115 kV bus tie in series with the existing bus tie at Lockport to correct voltage and thermal concerns, **Planned for Completion in Spring 2013**. (C31482)
- Conversion of a 10.5 mile 69 kV circuit between Mortimer and Golah stations to 115 kV to prevent low voltage conditions; this will include modification of the Mortimer and Golah terminals, **Planned for Completion in Spring 2013**. (C24629, C24630 and C24631)
- Improvement of the power factor at several 115 kV connected distribution stations in the Brockport and Batavia area to boost area voltages, **Planned for Completion in Spring 2013**.

In addition to these projects, the implementation of several other projects that are driven by age and condition will result in improvements of the system performance. These projects were developed with system needs in mind and their impact on the area has been incorporated into the evaluation of the system. For example, the replacement of the Gardenville transformers eliminated a previously approved project which called for the addition of a second 230 kV bus tie at Gardenville.

As these projects are driven by requirements outside of this program, they are not justified in this document. They are only referred to in this document to highlight how the various projects will all work together to create a robust and complete plan to support the area.

Frontier Region

- Rebuilding the existing Gardenville 115 kV station to a full breaker and a half configuration, including two 120 MVAR capacitor banks
- Replacing Gardenville 230:115 kV 125 MVA transformers TB #3 and TB #4 with 333 MVA units
- Replacing Packard 230:115 kV 125 MVA transformers TB #3 and TB #4 with new 125 MVA units

Southwest Region

- Reconductoring the northern 21 miles (65 mile total length) of the Gardenville – Homer Hill 115 k V circuits #151/152
- Reconductoring the Gardenville – Dunkirk 115 kV circuits #141/142

Genesee Region

- Reconductoring the Lockport – Mortimer 115 kV circuit #111

DRIVER(s):

Studies of the 115 kV and 230 kV transmission systems were conducted for the Frontier, Southwest and Genesee regions of Western NY, which extend from the NY/Canada border east to Mortimer Station and South to the Pennsylvania border. These studies were put in place in order to determine whether the systems comply with reliability standards. Studies were performed in 2007 and then reconfirmed in 2008 and evaluated the system for existing load levels up to a 10 year forecasted load level.

Included within both of these evaluations was testing of both N-1 and N-1-1 design criteria, ensuring compliance with NERC TPL Standards, NPCC Document A-2, NYSRC Reliability Rules and the The Company Transmission Planning Guide (TGP 28). These standards require the entire transmission system to meet N-0 and N-1 voltage, thermal and stability criteria as well as the bulk power system and long lead time items to meet the same criteria for N-1-1 conditions.

Several reliability criteria violations for the area were discovered under study conditions. Violations included thermal overloads on 115 kV circuits in the Frontier region (N-1), 230 kV and 115 kV voltage problems at Gardenville (N-0, N-1 and N-1-1), thermal overloads on transformers at Gardenville (N-1-1), voltage problems around Homer Hill and Dunkirk (N-0, N-1, N-1-1), and voltage problems around Batavia, Brockport and Golah (N-1).

For the Frontier region, system reinforcements are driven by the need to correct thermal overloads on the circuits between Packard, Tonawanda and Gardenville. These overloads occur for double circuit tower outages of the parallel circuits such as the Packard – Tonawanda #129 and #130 circuits or the Niagara – Tonawanda #177 and the Packard – Tonawanda #179 circuits. The overloads also occur for a double circuit tower outage of the Packard – Huntley 230 kV circuits #77 and #78. These overloads are worse when the outages are combined with an outage of one of the 230 kV circuits between Niagara and Gardenville as required by N-1-1 criteria.

The voltage at Gardenville is also outside of criteria for the system with all lines in service and for N-1 and N-1-1 conditions. The worst voltage problem is created by outages of 230 kV lines or N-1-1 outages of multiple 230 kV lines. The capacitor banks to be installed at Gardenville as part of the station refurbishment project will correct many voltage concerns but do not address all N-1-1 conditions. Similarly, correction of the overloads on the 115 kV circuits between Packard, Tonawanda and Gardenville is difficult using only reconductoring. Utilizing retired in place circuits, which share double circuit towers with the circuits to be reconductored, allowed the creation of a new line between Packard and Gardenville. This new line reduced the loading on the parallel circuits, correcting overloads and strengthening Gardenville by alleviating voltage problems. The new line also reduces the loading on the Gardenville transformers. However, any overload concerns would be corrected by the replacement of the before mentioned banks for condition reasons. The transformers will reduce the stress on the 230 kV system, which will help correct voltage problems.

In the Southwest region, the study assumed that the most critical generator, Indeck Olean was out of service, the Warren – Falconer #171 circuit was out of service and the Town of Jamestown presented a load of nearly 80 MW. The Jamestown load and outage of line #171 are documented to have occurred during previous heavy load periods. With these system conditions, the Homer Hill area voltage was below 90% with all lines in service. Double circuit tower contingencies of the Gardenville – Homer Hill or the Falconer – Homer Hill circuits were found to cause the voltage to fall to a point that the model could no longer solve. Because the existing voltage is below 90%, any single reinforcement would likely only correct the problems with all lines in service. Multiple reinforcements are required to correct all N-1 conditions. In addition to the problems in the Homer Hill area, bus faults at Dunkirk will create low voltage problems on the circuits between Dunkirk and Falconer.

For the Genesee region, several voltage related problems were found in the Batavia and Golah areas. For bus faults at Lockport, voltage problems develop in the Batavia area. Thermal concerns were also present on one of the circuits between Lockport and Batavia. At Golah, an outage of the circuit between Mortimer and Golah would result in Golah being fed radially from Batavia. This in turn would cause low voltage levels at Golah (below 80%). This contingency can also be caused by bus faults at Mortimer and Golah.

Many of these problems have been identified for existing load levels and will worsen for forecasted load levels. As a result, voltage support and correction of thermal overloads is needed as soon as possible. These problems can be addressed by operational means in the short term, until this major program of reinforcements is delivered.

With the exception of supporting the Gardenville 230 kV voltage, all projects are done to comply with the The Company Transmission Planning Guide (TGP 28). The majority of projects address N-0 or N-1 system concerns on the 115 kV system. Some of the voltage support projects in the Southwest region are also addressing N-1-1 conditions with a transformer (long-lead time item) out of service. Concerns with the Gardenville voltage are also present for N-1 and N-1-1 conditions.

OTHER ALTERNATIVES CONSIDERED:

In the Frontier region, instead of reinforcing the 115 kV system to correct the thermal and voltage issues, consideration was given to reinforcing the 230 kV system. This could be accomplished by adding a new 230 kV circuit between Packard and Gardenville. Review of this option revealed that the necessary right of way was not currently available without retiring existing 115 kV circuits. Retiring these circuits would have a negative impact on the system.

In the southwest region, studies considered alternatives involving the reinforcement of Gardenville and/or Falconer. It was found that the distance between these stations and Homer Hill, combined with the double circuit tower outages, resulted in these options not addressing area problems adequately. Reconductoring with capacitor bank additions and power factor improvement was also considered, but analysis indicated that this solution would be more costly and have a shorter longevity.

For the Genesee region, various combinations of capacitor banks and power factor corrections were considered. The voltage problems in the Golah area can not be corrected with capacitance alone. It was not possible to address any of the other problem areas with capacitor bank and power factor corrections alone. The recommended reinforcement provided the most improvement with the least amount of upgrades.

CUSTOMER BENEFIT(s) OF PROGRAM:

Customers will benefit from this program in several ways, including:

- Their exposure to service interruptions (some resulting from load shedding) in the event that certain key contingencies were to occur would be reduced significantly.
- Generation that currently must be run at times to ensure will no longer be required, avoiding future costs of dispatching the generation out of NYISO merit order.
- The backup source to loads in the Homer Hill area will be operated normally closed, reducing the frequency and length of outages for certain contingencies.
- Some capability to accommodate new or expanding load will be added to the system.

The planned approach is designed to prevent thermal and voltage problems that have developed over time and that would negatively affect system security and reliability throughout western NY. This will be accomplished by reconductoring circuits, adding new or upgraded connections to the higher voltage system and adding reactive support. Without system reinforcements, if a contingency were to occur, load shedding would be required to maintain the system performance at an acceptable level. The approach will allow for modest growth in the near term, remove the reliance on generation, and strengthen ties to Pennsylvania.

Transmission system reliability improvements will develop through the implementation of the before mentioned solutions. In the Frontier region, the rebuild of double circuit 115 kV transmission lines between Packard, Paradise and Gardenville will address the majority of reliability concerns on these circuits. The lines to be rebuilt are the Packard – Tonawanda

#178 and the Tonawanda – Gardenville #180. Today, these circuits are called the Packard – Erie #181 and Packard – Gardenville #180. Line #180 is 29 on the Worst Circuit List, line #181 is 130. on the list.

The reconductoring of the Falconer – Warren #171 circuit is also expected to result in an improvement in performance. It is currently 98. on the worst circuit list. This line is also often out of service due to overload concerns. If the line is predicted to overload, it is opened by First Energy, prior to the overload occurring. Once the line is reconductored, it is expected to be in-service almost continuously.

The construction of a new 345/115 kV station near Homer Hill will be splitting the existing #151 and #152 circuits into four lines. The 345 kV line will also be split into two circuits. The reduced length of these circuits will reduce the exposure, which is expected to result in a reliability improvement.

As part of the plans in the Southwest region, the way line #157 is operated will be changed. Currently, the line is operated radially out of Homer Hill. A switch at Andover is kept open, but could be closed as a backup source to the load supplied from the line. Switching the load over to the backup takes time. Once the line is operated as normally closed at Andover, fewer faults will interrupt the loads and backup will be instantaneous. Even for those faults that interrupt loads, it is expected that restoration times will be improved by the increased flexibility introduced by the normally closed operation.

METRICS TO TRACK BENEFIT(s):

The effectiveness of the program will be evaluated by the programs ability to correct thermal and voltage problems in the system.

COSTS AND AVOIDED COSTS:

The construction of new facilities, as part of the Reliability Criteria Compliance Strategy, will cause an increase in the total OPEX spend for The Company's New York Transmission System. This increase is a result of the following planned preventive maintenance programs associated with new equipment/facilities:

- Visual and Operational Inspections
- Mechanism Tests
- Diagnostic Tests
- Dissolved Gas Analysis Tests
- Line Maintenance and Inspection Programs

Reduction in Trouble Maintenance

Since the Reliability Criteria Compliance Strategy proposes the addition of new equipment/facilities, no reductions in trouble calls are anticipated. In fact, an increase in trouble calls is expected to address any potential issues associated with the addition of 4 new capacitor banks. These capacitor banks generally require pre-peak and general maintenance to be performed on an annual basis. The annual cost per capacitor bank is estimated to be

$2,600/year. This will result in a total estimated expenditure of $10,400/year for all 4 capacitor banks.

Planned Preventive Maintenance

Visual and Operational Inspections

Part of the Reliability Criteria Compliance Strategy includes the construction of a new 345:115 kV station near Homer Hill station tying into Homer City – Stolle 345 kV line #37 and Gardenville – Homer Hill 115 kV lines #151 and #152 to support area voltage. This new station will require Visual and Operational Inspections on a monthly basis at an estimated cost of $400/month, which equates to $4,800/year.

Mechanism Test

In total, the Reliability Criteria Compliance Strategy proposes the addition of 20 new breakers (16 – 115 kV breakers, 1 – 230 kV breaker, and 3 – 345 kV breakers). Each one of these new breakers will require mechanism test to be performed on a 24 month period. The estimated cost of each test is $800/test, which equated to $400/year per breaker. This will result in a total estimated expenditure of $8,000/year for all 20 breakers.

Diagnostic Test

In addition to the mechanism tests, the 20 new breakers also require diagnostic tests to be performed every 108 months. The estimated cost of diagnostic test for 115 kV and 230/345 kV breakers are:[116]

- 115 kV: 3 Technicians/16 Hours Every 108 months – $533/yr
- 230/345 kV: 4 Technicians/16 Hours Every 108 months – $711/yr

This will result in a total estimated expenditure of $11,400/year for all 20 breakers. Diagnostic test will also be required for the one new transformer being proposed in the Reliability Criteria Compliance Strategy (345:115 kV transformer for the new station near Homer Hill). The diagnostic test for transformers is performed every 72 months at an estimated cost of $12,000/test. This equates to an annual cost of $2,000/year per transformer.

Dissolved Gas Analysis (DGA) Tests

In addition to the diagnostic test, the new transformers will also require a DGA test every 6 months. The cost of these tests is estimated to be $400/tests, which equates to an annual expenditure of $800/year.

In total, it is estimated that a gradual increase in OPEX spend will be realized starting at approximately $18,000 in 2012 and totaling about $36,000 once the program has been fully placed in service by 2014.

[116] Data based on The Company maintenance standards and current work practices. Labor rates based on $100/hour

EXHIBIT 11

PROGRAM NAME:

Syracuse Area Reconductoring Project

PROGRAM DESCRIPTION:

This program reinforces the transmission system in and around the Syracuse, NY area. These reinforcements are necessary to respond to a reliability need caused by load growth in the area over the period of time from 2008 to 2018. Without this program, the 115kV system will be exposed to thermal overloads during contingency conditions.

The program scope includes the following:

- Reconductor 6.36 miles of the Yahnundasis – Porter 115 kV circuit #3 due to thermal overloads.
- Reconductor two separate sections of the Clay – Teall 115 kV circuit #10 due to thermal overloads. The sections targeted for reconductoring are 6.75 miles, and 6.08 miles.
- Reconductor 10.24 miles of Clay – Dewitt 115 kV circuit #3 due to thermal overloads.

DRIVER(s):

Studies of the 115 kV and 230 kV transmission systems were conducted for the Central and Mohawk Valley regions of Central NY, which extend from Elbridge substation in the West to Inghams substation in the East, to determine whether the systems comply with reliability standards. These studies, which were performed in 2007 and then reconfirmed in 2008, evaluated the system for existing load levels up to a 10 year forecasted load level.

Included within both of these evaluations were testing of both N-1 and N-1-1 design criteria to comply with NERC TPL Standards, NPCC Document A-2, NYSRC Reliability Rules and the The Company Transmission Planning Guide (TGP 28). These standards require the entire transmission system to meet N-0 and N-1 voltage, thermal, and stability criteria. Also, they require the bulk power system and long lead time items to meet the same criteria for N-1-1 conditions.

Several reliability criteria violations for the area were discovered under study conditions. Violations include thermal overloads on 115 kV circuits in the Central region for N-1 and N-1-1 conditions.

In the Mohawk Valley region system reinforcements are driven by the need to correct thermal overloads on the circuits between Yahnundasis and Porter. During a number of contingencies which include faults on either 115 kV bus at Porter substation, many of the breakers at Porter and Oneida substations, and any outages along the Oneida-Porter #7 line, or the Porter-Boonville #1 line, the segment of Yahnundasis-Porter #3 spanning from Walesville tap to Porter (a section of 4/0 CU conductor) sees thermal overloading. These overloads range from 100.2% (118.9MVA) to 128.9% (147.7MVA) of its LTE rating. These overloads were identified for a summer peak using a 2008 system case, and persisted for the 2013 and 2018 Summer peak cases.

In the Central region, two separate system conditions resulted in overloaded lines. During a stuck-breaker contingency of Clay Substation's R825, which would trip 345-115kV TB #1 as well as South Oswego-Clay line #4, thermal overloads were seen on segments of Clay-Teall #10. This overload was 114.9% of LTE (134.6MVA). Lesser overloads on this line were also observed during stuck-breaker contingencies of Clay R855 (outages of Clay-Teall #11 and Clay-Lighthouse Hill #7), outages of Dewitt TB#2, and Teall Avenue 115kV bus "B." Additionally, during a stuck-breaker contingency of Clay Substation's R825, thermal overloads were observed on segments of Clay-Dewitt #3. This overload was 101.1% of LTE (118.4MVA). These overloads were identified for a summer peak using a 2008 system case, and persisted for the 2013 and 2018 Summer peak cases.

Many of these problems have been identified for existing load levels and will worsen for forecasted load levels. As a result, correction of thermal overloads is needed as soon as possible. These problems can be partially addressed by operational means such as dispatch of all the Syracuse local generation in the short term, until this program of reinforcements is delivered. Should the project not be undertaken, the risk is the creation of "must run" units in the Syracuse area.

All projects are done to comply with the The Company Transmission Planning Guide (TGP 28). These projects address N-1 and N-1-1 system concerns on the 115 kV system.

OTHER ALTERNATIVES CONSIDERED:

In the Central region, studies considered the full-time installation of the spare 345-115 kV transformer bank at Dewitt substation as an alternative to the Reconductoring projects. While this solution was found to be a workable solution to the overloads associated with Clay substation, it created a number of other concerns. Namely, the, overdutied circuit breakers at Dewitt substation, and the thermal overload of the Ash – Teall 115 kV underground cables during contingency.

In the Mohawk Valley region, studies considered alternatives involving the reinforcement of Oneida and/or Yahnundasis substations. It was found that the reinforcement of these stations did not sufficiently address area problems.

CUSTOMER BENEFIT(s) OF PROGRAM:

Customers will benefit from this program in several ways, including:

- The likelihood of their exposure to service interruptions (some resulting from load shedding) in the event that certain key contingencies were to occur will be reduced significantly.
- Avoidance of “must run” units being created to alleviate post-contingency violations.
- Some capability to accommodate new or expanding load will be added to the system.

Should the contingencies which cause the overloading of the Yahnundasis – Porter line occur prior to this project, the result would be shedding of load in the Yahnundasis area. This project would eliminate the potential for that solution to be needed, improving the reliability of the system in that area, and reducing interruptions due to load shedding.

In addition to compliance with NPCC and NYSRC requirements, the benefits of completing these projects are reductions in system vulnerability to certain severe contingencies. These projects reduce the chances that thermal overload would occur for these contingencies:

- Faults on either 115kV bus at Porter substation
- Faults on breakers at Oneida or Porter substation
- Outages on the Oneida – Porter #7 line
- Outages on the Porter – Boonville #1 line
- Stuck-Breaker contingencies on Clay R825
- Stuck-Breaker contingencies on Clay R855
- Outages of Dewitt TB#2
- Faults on Teall Ave. Bus “B”

Customers in central New York will benefit from the reduced vulnerability of the transmission system due to these disruptive contingencies. Additionally, some capability to accommodate new or expanding load will be added to the system.

METRICS TO TRACK BENEFIT(s):

The effectiveness of the program will be evaluated by the program’s ability to correct thermal problems in the system.

COSTS AND AVOIDED COSTS:

These projects will not produce savings of operating expenditures under normal system conditions. However, completion of this work will make the transmission system less vulnerable to system instability and voltage collapse for certain extreme contingencies.

If one of those contingencies was to occur, and the upgrade projects were not implemented, then there could be substantial operating expenses associated with the system restoration process. Customers over a wide area would incur costs resulting from loss of supply during the restoration period. These costs have not been calculated or estimated; however, costs for a single event could exceed the entire cost of the projects.

EXHIBIT 12

PROGRAM NAME:

3A/3B Tower Replacements

PROGRAM DESCRIPTION:

Partial Structure Replacement of the New Scotland-Leeds 93 & 94, Leeds-Athens 91, and Athens-Pleasant Valley 95 345 kV Lines

DRIVER(s):

The Edic-New Scotland 14 line was first energized in 1962. Physical components of the line include twin 7/16" high strength steel static wires and a two conductor per phase arrangement of 795 kcm Aluminum Conductor Steel Reinforced (ACSR) “Drake”, supported by steel lattice towers. There are six tower types on the line, designated as Types 3A, 3B, 3D, 3E, 3F and 3FF. The type of suspension structures used on the Edic-New Scotland 14 rely heavily on the static wire and phase conductors to help offset imbalances in longitudinal loading . Company analysis indicates that extreme longitudinal wind loading generated by storms has been the cause of each of the three failures identified above. The 3A/3B structures were originally designed to meet the National Electric Safety Code (NESC) of 1949.

Failures of tower types 3A and 3B have occurred since the line entered service. In October 2003, Structure 347, a 3A tower, failed. Two previous failures occurred on 3B towers: Structure 3 in 1977 and Structure 66 in 1992 (adjacent towers 63, 64, 65, 67, and 68 were damaged by the collapsed tower).

Phase I addressed safety concerns on the Edic-New Scotland 14 line and has been completed. The selection of towers for replacement involved considerable analysis determining which towers presented the greatest public safety concern and replace them.

The Company has four other 345 kV lines that use these same types of towers. They are the 345kV New Scotland–Leeds 93 and 94 lines, Athens-Pleasant Valley 91, and Leeds–Pleasant Valley 92 lines. The physical components of these lines include twin high strength steel static wires and a two conductor per phase arrangement of 795 kcm Aluminum Conductor Steel Reinforced (ACSR) “Drake”, supported by steel lattice towers. These lines were energized in 1962.

Phase II will address these four remaining lines after Transmission Planning and the NYISO review the future load needs associated with them. This is expected to be completed in calendar year 2010.

OTHER ALTERNATIVES CONSIDERED:

Option 1: Do Nothing Until Failure Occurs.

Reason for rejection: The Company and Niagara Mohawk have experienced tower failures three times over the life of the line, which our analysis indicates were caused by high wind speeds.

Option 2: Use of Guys to Improve Structural Wind Performance. Install guys on Type 3A/3B towers to improve structural wind performance. This also involves a limited amount of structural reinforcement on the guyed structures.

Reason for rejection: Use of the guys will potentially increase the outage risk by 0.42 while the improvement in the towers will decrease the risk by 0.125. Estimated average annual outage duration is 130 minutes. There is increased exposure to electrical contact and personal injury in any vehicle (trucks, automobiles, tractors, snowmobiles, etc.) striking a guy wire.

Option 3: Replace Type 3A/3B Towers at Critical Crossings and to Prevent Significant Cascading (recommended). Replace towers adjacent to road crossings, towers adjacent to railroad crossings, towers adjacent to navigable waterways, towers replaced to reduce excessive cascading potential (when more than 16 towers/structures could fail), and towers at transmission line crossings.

Option 4: Replace all 3A/3B Towers. This involves the replacement of almost 1400 towers on all five lines (including the Edic-New Scotland 14 line).

Reason for rejection: High cost of tower replacements with a limited safety impact.

CUSTOMER BENEFIT(s) OF PROGRAM:

The scope of this program is being developed with consideration of the overall risks to public safety as the primary driver with improved reliability as a secondary benefit. The Company chose public safety as the main criterion for replacement because it determined that a limited replacement would utilize customer funds judiciously while correcting a potential public safety risk. The critical importance of the four lines requires the use of expensive construction methods (live line work), as costs for materials have risen. Thus, The Company has limited the program to those towers which pose the greatest risk to public safety.

- towers adjacent to road crossings
- towers adjacent to railroad crossings
- towers adjacent to navigable waterways
- towers replaced to reduce excessive cascading potential
- towers at transmission line crossings

METRICS TO TRACK BENEFIT(s):

The replacement structures are now designed to meet the NESC 2002 code and can withstand higher wind loadings in the longitudinal direction. The Company and Niagara Mohawk have experienced tower failures three times over the life of the line, which our analysis indicates were caused by high wind speeds.

COSTS AND AVOIDED COSTS:

The OPEX savings from the replacement of 139 Type 3A and 3B towers comes mainly from the decreased planned preventive maintenance.

Reduction in Trouble Maintenance

No significant reductions in trouble calls are anticipated. The past failures of the Type 3A-3B towers required replacement of the structure (a capital cost). While some associated OPEX costs might be incurred, this is not easily predicted.

Decreased Planned Preventive Maintenance

Due to a history of vibration problems and failures, The Company introduced a climbing inspection once every 5 years for Type 3A/3B towers in 2006. The 139 towers that will be replaced will not require this inspection:

Climbing inspections

Average Program Cost: $1,385 per structure

Cost for 139 towers over 5 years: $192,515

Average annual savings: $38,503

Based on this, current OPEX costs will decrease by $38,503 per year. As this was a new maintenance policy introduced after the 2001 rate plan finalized, these costs have not been included as OPEX savings.

In addition to a reduction in climbing inspections, a one time savings on painting and footer inspections is expected. Consistent with paragraph 19 in Strategy SG052, approved on 24 Feb 2006, the new steel structures will not be painted during the first painting cycle after installation.

	Per Structure	Years	Annual (ave)
Painting	2,600	15	$173
Footer	1800	20	90

Painting

Steel Towers Replaced: 139

Average annual savings: 139 x 173 ≈ $24,000

<u>Footer Inspections & Repairs</u>

Steel Towers: 139

Projected Savings: 139 × $90 ≈ $12,500 per year

The Company reinstated the painting program after the acquisition of Niagara Mohawk. Although towers have been painted throughout their lives, this OPEX program had been discontinued by Niagara Mohawk for a number of years prior to the acquisition. Therefore, this is not included as an OPEX savings to the base program.

The footer inspection & repair did exist at the time of the acquisition and so these savings are included in the chart below.

The Company has four other 345kV lines that use these same types of towers. They are the 345kV New Scotland–Leeds 93 and 94 lines, Athens-Pleasant Valley 91 and Leeds–Pleasant Valley 92 lines. About 1½ the number of towers exist on these lines as the Edic-New Scotland 14 line. Thus, if we assume about 210 towers will be replaced in a similar fashion on the remaining 4 lines, with about 140 tower in FY2014/15. The FY2014/15 OPEX savings will double.

The average incremental maintenance spending this fiscal year and over the next 4 years is reduced by:

	FY2010/11	FY2011/12	FY2012/13	FY2013/14	FY2014/15
Total (Approx.)	$12,500	$12,500	$12,500	$12,500	$25,000

EXHIBIT 13

PROGRAM NAME:

Relay Replacement Strategy

PROGRAM DESCRIPTION:

This program identifies the relays most in need of replacement based on (a) poor condition or historical performance (including relays within the same family) or (b) obsolescence where parts or knowledge are no longer available internally with Niagara Mohawk or externally within Manufacturers.

Specifically, the scope includes about 650 high priority relays to be replaced in the next five years. In cases where a large number of relays are to be replaced in a control house that is itself in poor condition, the entire control house will be replaced including all the relay packages contained within.

This program includes 3 projects with forecasted spending levels greater than $2 million, such as the Menands Control Building project.

DRIVER(s):

This strategy is driven by the need to ensure a reliable Transmission network for the benefit of our customers. Relays are unlike other high voltage equipment that wear out in somewhat predictable and observable ways. While electromechanical (EM) protective relaying systems continue to perform their basic design functions, they do not have any type of monitoring to provide the status of the relay. EM relays can degrade over time and the only way to identify a problem is through routine tests or if the relay fails. In addition, the poor technical performance of some relays has significant negative effects on the secure, high-speed and reliable operation of the system under today's increasing load demands and stresses.

After a relay is installed in perfect condition deterioration takes place which, in time, could interfere with correct functioning. For example, contacts may become rough or burnt due to frequent operation, or tarnished due to atmospheric contamination. Coils and other circuits may be open-circuited, auxiliary components may fail, and mechanical parts may become clogged with dirt or corroded to such an extent that they may interfere with movement. One of the particular difficulties of electro-mechanical relays is that the time between operations may be measured in years during which defects may have developed unnoticed until revealed by the failure of the relay to respond to a system fault. Although testing is required on a periodic basis, there is no guarantee that the relays will continue to operate properly once the tester has left the facility.

A power system represents a substantial investment and consumers rely on the product (energy) for their livelihoods and lifestyles. Transmission power system outages experienced by consumers can be mitigated by deploying switchgear and protective relaying systems. A relay or group of relays can detect system anomalies and signal a circuit breaker to trip, thus preventing an outage or limiting its impact. The purposes of the relays are to provide reliability and stability to the system being protected. This is accomplished by measuring the system waveforms and reacting based on pre-established operation characteristics.

Evidence from relay testers suggests that calibration is becoming problematic due to component drift in the electro-mechanical relays and faulty circuit boards which are problematic in a number of solid state relay families. In addition, many of these relay families are not supported by the manufacturers such that spare parts and the knowledge base are no longer available.

The NY transmission system is protected by nearly 8,000 relays of which about 6,500 are electro-mechanical or solid state types (the remainder are microprocessor based). These relay types represent 81% of the installed transmission relay base. The electro-mechanical relays have an anticipated asset life of 35 to 50 years while the solid state devices have shorter lives anticipated to be between 15 to 20 years. With over 6,500 relays protecting the NY transmission system, many of which are at or near their end-of-life, it is necessary to develop a replacement plan to target the worst performing families of relays before they fail to operate correctly.

Design Type	**# of Relays**	**% of Total**
Electromechanical	6,240	78%
Solid State	287	4%
Microprocessor	1,439	18%
Total All Relays	7,966	100%

Table 1 – Count of relays by type

While in the longer-term thousands of electro-mechanical relays may need replacement based on a purely age based analysis, our condition assessment yields an immediate need to replace over 650 relays (approximately 10% of the total non-microprocessor relay population) where poor performance and obsolescence places these relays at a higher risk of failure than what is acceptable for satisfactory operation.

OTHER ALTERNATIVES CONSIDERED:

Do nothing – This option maintains the status quo. As relays continue to degrade towards end-of-life, the volume of unsupportable relays will increase resulting in reduced transmission system reliability due to mis-operations. Failure to correctly detect and isolate faulty transmission equipment can lead to serious system instability, local losses of supply and in the extreme, widespread blackouts.

Life extension: To manage the increase in relays reaching end-of-life, measures could be undertaken to extend the life of certain electromechanical relays. This however has limited scope as parts and technical knowledge are increasingly unavailable making attempts to extend life impractical or uneconomic.

Deferral: Delay of this strategy will result in additional relays reaching end-of-life such that they may be unreliable. Unreliability will exhibit itself in situations where the protection system is called upon to isolate faulty equipment. Another failure mode could be that a relay becomes active when it has not been requested to.

Systematic relay replacement (Recommended) – The recommended strategy identifies the worst performing relays. With 10% of the non-microprocessor relay population requiring replacement, this strategy allows the company to identify the worst performing relay families and remove them from the system. They will be replaced with more reliable and efficient microprocessor based relays.

CUSTOMER BENEFIT(s) OF PROGRAM

Replacement of these electromechanical and solid state relays is required to manage the degrading population and to ensure that the advantages of new technology are fully leveraged and realized. The main strategy moving forward will use a systematic approach. Rather than concentrating on a particular protection component, a review of the entire protection system and substation will be completed. This integrated approach will allow for utilization of microprocessor based protection systems. For example, microprocessor relays have the ability to calculate distance-to-fault, which aids in quicker restoration following a power system disturbance. Also, microprocessor relays contain oscillography which allows a more thorough investigation of system events. The relays contain internal watchdog monitors that alarm for relay problems in some cases minimizing the more frequent need for periodic preventative maintenance.

The result of this strategy will be increased reliability of the transmission protection and control system where known poor performing relays are replaced with microprocessor based relays. This replacement will also yield additional operation data that was not previously available.

The greatest threat to the security of a transmission system is the short-circuit, which imposes a sudden and sometimes violent change on system operation. The large current which then flows, accompanied by the localized release of a considerable quantity of energy, can cause fire at the fault location and mechanical damage throughout the system, particularly to machine and transformer windings. Rapid isolation of the fault by the nearest circuit breaker will minimize the damage and disruption to customers. When a system is large, the chance of a fault occurring and the disturbance that a fault would bring is so great that without equipment to remove faults the system will become, in practical terms, inoperable. A system is not properly designed and managed if it is not adequately protected. This is the measure of the importance of protective relays to customers. For a protective relay scheme to operate successfully, it requires a high degree of reliability. A systematic approach to the replacement of the worst performing relays ensures that the transmission system is at all times adequately protected.

The replacement relays will be microprocessor based and capable of supporting multiple functions within one device thus replacing numerous discrete electro-mechanical relays. Furthermore, the digital nature of the relays facilitates advanced data management providing the company with more accurate information than previously available.

METRICS TO TRACK BENEFIT(s)

The success of this program will be measured by a reduction in the number of poor condition or poor performing relays on the system. In addition improvements in SIADI, CAIDI and LCM will be achieved through the reduction of the number of relay mis-operations (both failure to trip and over tripping). In other words, by the end of the program, sustained outage causes attributed to system protection will go down (currently, 5% of the total Load Sustained Outage Causes are attributed to system protection).

COSTS AND AVOIDED COSTS:

The relay replacement program offers The Company the opportunity for both preventative and troubleshooting maintenance savings in the long term. Driving these savings would be the increase of the preventative maintenance cycle of six years for microprocessor relays compared to the four year cycle for electro-mechanical relays. Also, microprocessor based relays offer other advantages of self diagnostic testing, more secured settings that never require recalibration and are less prone to failures. Furthermore, for a typical bulk transmission line with two relay packages (a primary and a back-up), only two microprocessor relays would be required as opposed to eight to ten electro-mechanical relays.

It will take many years for this program to realize the benefit of expected OPEX savings as a result of the migration to microprocessor based relays simply because there are so many electro-mechanical relays still across the The Company System. Any savings realized at first by new microprocessor relays placed into service will be reallocated to maintaining the still vast majority of electro-mechanical relays.

<u>Decreased Planned Preventive Maintenance</u>

The replacement of 80 relays in NY will result in overall lower maintenance cost. This cost has been estimated as shown below:

Decreased O&M

Periodic Test for electromechanical relays:

1 Technician/8 Hours Every 4 years	$16k/yr

Periodic test for microprocessor relays:

1 Technician/8 Hours Every 6 years	$ 11k/yr
Net Decreased O&M savings @ $100/hr	$ 5k/yr

The relays are scheduled to be replaced over the next three years; therefore the full savings will not be realized until the end of the replacement cycle.

Based on an estimated decrease in planned preventive maintenance, savings of $5,000/year should be realized.

EXHIBIT 14

PROGRAM NAME:

Flying Ground Strategy

PROGRAM DESCRIPTION:

This program replaces all seventeen flying ground switches in service in the Western New York area and two flying ground switches at Trinity station in the Albany area of New York. These switches are currently utilized as transformer protection devices and were manufactured by Haefely Trench and Delta Star.

The switches were installed in the mid to late 1950s and over time have seen their operating speed decrease because of worn linkages and other mechanical components. In order to operate the low-side circuit breaker during a transformer high-side fault, these switches subject the transmission system to a second fault and disturb the system more than necessary. This protection arrangement subjects the transformer to longer duration faults, thereby increasing the likelihood of internal damage to the transformer and the safety risk to site personnel. Reopening the flying ground switch to re-cock it after a fault is becoming very difficult, due to worn out mechanical components and switch adjustment problems.

The flying ground switch and its associated maintenance switch are mounted on steel box structures that will be removed. A new S&C 2000 series model 2010 circuit switcher or an approved equivalent will be installed in order to provide both switching and interrupting capabilities that meet the current The Company protection policy.

DRIVER(s):

This project is driven by the necessity to improve reliability as well as safety. The existing flying ground switches have reached the end of their useful life. Degradation of the switches can lead to a higher probability of equipment miss-operations or the complete inability to operate equipment. Replacing the flying ground switches with new circuit switches will provide both switching and interrupting capabilities that meet the current The Company US Protection Policy.

Failure of a flying ground switch to operate correctly may cause a significant delay in clearing faults with consequential disruption to customers. Slow fault clearance could also result in a more sustained fault leading to significant equipment damage, potential safety issues, and longer customer outages.

The flying ground switches are no longer reliable and cannot be rebuilt because spare parts are no longer available from the manufacturer. The repair of the flying ground switches does not comply with modern protection standards.

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Do nothing: This option would involve no proactive replacements of assets, instead assets will be replaced as failure occurs. The condition of the flying ground switches is such that it is increasingly likely that a failure will occur, leading to a disruption in the Buffalo area. Unplanned replacements almost always cost more than planned replacements and therefore, this option is not considered acceptable.

Option 2 – Refurbishment: Repair of existing flying ground switches was considered, but was rejected because it does not comply with modern protection standards. Neither replacement parts, nor manufacturer's support are available for the 50-60 year old equipment.

Option 3 – Replacement: The replacement of the flying ground switch is the recommended option. A circuit switcher meets modern protection standards, provides both switching & interrupting capabilities, offers improvements in reliability/safety and meets The Company's US Transmission Protection Policy.

Option 4 – Defer replacement: This option was rejected because the flying ground switches are no longer reliable and cannot be rebuilt since spare parts are unavailable.

CUSTOMER BENEFIT(s) OF PROGRAM:

Replacing the flying ground switches with a circuit switcher meets modern protection standards, provides both switching & interrupting capabilities, and offers improvements in reliability/safety.

METRICS TO TRACK BENEFIT(s):

The success of this project will be measured by a reduction in the number of flying ground switches remaining on the system by the end of 2013 and by improvements in CAIDI, SAIFI and LCM.

COSTS AND AVOIDED COSTS:

There will be a minor reduction in O&M costs associated with damage/failure repairs. No reduction in planned maintenance cost is anticipated.

EXHIBIT 15

PROGRAM NAME:

Federal Pacific RHE Breaker Replacement Program

PROGRAM DESCRIPTION:

Condition based replacement of the RHE Oil Circuit Breakers (OCB's).

The program includes the replacement of three 115kV RHE oil circuit breakers two at Oneida and one at Lighthouse Hill (R50, R70 and R60 respectively). Lighthouse Hill is planned to be rebuilt by the end of FY13/14 and Oneida substation planning will begin by the end of FY09/10.[117]

DRIVER(s):

Due to the key function carried out by circuit breakers, particularly for fault clearance, they cannot be allowed to become unacceptably unreliable. The Federal Pacific RHE circuit breakers are in poor condition, have a history of failure, lack adequate spare parts and have experienced mechanism, bushing, and interrupter problems.

There have been three RHE breaker failures. All three failures occurred at Rotterdam, even though prior diagnostic inspections provided no indication of imminent failure.

With historical data depicting the earliest onset of breaker failures occurring in the forty year range, the possibility of these breakers failing during fault interruption duty is increasing. The Company has already experienced failures of bulk oil circuit breakers within the transmission system in New York. Equipment failures at these high voltages (115 kV and above) have the potential to be extremely dangerous, resulting in erratic voltage dissipation and flying debris. In many cases, adjacent equipment is damaged, further increasing the risk of injury and customer outages.

Environmental concerns associated with oil filled equipment failures are also an issue. Typical bulk oil circuit breakers contain 1500+ gallons of oil. Incidents have occurred where the force resulting from the circuit breaker failure was powerful enough to rupture the tank, causing extensive and costly environmental clean up.

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Replace after failure. There are adequate spares in the system to replace any breaker failure that may occur at these substations. However, given the consequences of failure this approach is not recommended.

[117] This program previously included the replacement of five 230kV RHE circuit breakers at Rotterdam. The replacement of these circuit breakers has now been transferred to the substation rebuild program.

Option 2 – Planned replacement. Due to the key function carried out by circuit breakers, particularly for fault clearance, they cannot be allowed to become unacceptably unreliable and therefore a planned replacement approach is recommended.

Option 3 – Defer replacement. This option is not acceptable given the current asset condition. Reliability, already at low levels, will continue to degrade as assets in poor condition continue to deteriorate. Due to the obsolete design, replacement parts are not available for RHE breakers and must be cannibalized from retired units.

CUSTOMER BENEFIT(s) OF PROGRAM:

The planned replacement of these circuit breakers reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

Implementing this strategy also addresses the need for reliable fault interruption capability for the safety of our employees and equipment. In addition, planned replacements are less costly and more efficient than unplanned replacements due to failures. Planned replacement offers the lowest lifetime cost approach for customers.

METRICS TO TRACK BENEFIT(s):

The success of these substation upgrade projects will be shown by an increase in the reliability of the upstate New York transmission system as seen by our customers.

The circuit breaker replacement strategy offers The Company the opportunity to improve the reliability performance of the transmission network. Reliability improvements will be measured by the following indices:

- SAIFI: System Average Interruption Frequency Index
- SAIDI: System average Interruption Duration Index
- CAIDI: Customer Average Interruption Duration Index

COSTS AND AVOIDED COSTS:

Typical cost data depicted below is derived from average annual preventative maintenance costs for the respective type of station equipment listed:[118]

- 115kV Oil Circuit Breaker (OCB) $1,500/yr
- 115kV Gas Circuit Breaker (GCB) $900/yr

Replacing these five oil circuit breakers now, with modern SF6 gas circuit breakers would realize a modest preventative maintenance expense reduction.

[118] Data based on The Company maintenance standards and current work practices. Labor rates based on $100/hour

EXHIBIT 16

PROGRAM NAME:

Substation battery replacement

PROGRAM DESCRIPTION:

This program will replace substation battery systems that are 20 years old on upstate New York's transmission system.

DRIVER(s):

Battery and charger systems are critical components needed to insure full substation operational capability during both normal and abnormal system conditions. The battery charger is used to rectify the AC local service to DC for the DC protection and control system, providing a float charge to the battery, and recharging the battery after discharge.

The useful life span for the typical lead-acid battery can vary by as much as 10 years. Studies indicate that at 80% of life, lead-acid battery performance drops off rapidly and the IEEE recommends that a battery should be replaced when capacity reaches 80-85% of original performance.[119] A battery may prove itself inadequate only after failing to perform in an emergency.

Under acceptable conditions the most common end of life failure modes are positive grid corrosion and electrolyte dilution. These failure modes are inherent in the design, inevitable and irreversible.[120] Per IEEE standards, a battery discharge test is necessary to accurately determine remaining lead acid battery life. To be effective, IEEE calls for this test to be performed periodically throughout the life of the battery starting at year two.[121] If this test is not performed an accurate measure of remaining battery life becomes very difficult to predict beyond a certain age (20 years). The load substation standard design of a single battery system does not allow a battery load test program initiative due to costs and the potential for damaging the batteries. Without available battery load test data an age based approach to replacement is required.

Most of the load substations (typically 115kV) in New York have a single substation battery system. Implementation of this program will deliver a sustained replacement program for substation batteries and their associated equipment. There have been at least three instances in the last five years where a connection problem (that would have prevented substation equipment to operate when needed) was found during annual battery maintenance.

[119] EPRI Report 10163, Technology Enhancements and Improved Practices for Existing Lead Acid Battery Systems
[120] David Linden and Thomas B Reddy, Handbook of Batteries, McGraw-Hill, New York, 2002
[121] IEEE Standard 450-2002

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Replace only battery systems showing visible deterioration:

This option would replace battery systems at failure or only after displaying visible signs of deterioration. This option will leave battery systems in service that may not perform as intended when most needed. This option exposes The Company and its customers to an elevated risk of battery system failure and the associated safety, reliability and financial consequences.

Option 2 (Recommended) – Replace at 20 years old or based on condition assessment:

This recommended option is the replacement of all battery systems over 20 years of age. This option is the most cost effective way of ensuring all battery systems on the network will perform as intended. This will reduce the possibility of an unavailable or inadequate DC power source impacting the substation protection, monitoring, and control capabilities in a negative manner. When a flooded lead acid battery system approaches its end of life there is a significant increase in the risk of battery cell connections and battery cell plates being unable to perform as originally designed.

Option 3 – Institute a battery load test program:

This option would allow for the determination of remaining battery life for all new installations. In this case, some batteries may have their lives extended by 5-10 years. However, the cost for this program is higher than just replacing the battery system at 20 years. In addition, there is no guarantee that the battery itself will last more than 20 years. If the IEEE testing standard is followed, it is too late to implement this program for any existing battery system over 5 years old.

CUSTOMER BENEFIT(s) OF PROGRAM:

An age based replacement is the recommended option, at this time. It is the most cost effective approach while maintaining an acceptable level of risk. This approach provides for the proactive replacement of battery systems at end of life to minimize the risk of battery system failure.

Replacement of battery systems that are at end of life is consistent with The Company's goal of improving system reliability for the following reasons:

- Batteries greater than 20 years old of life have a higher probability of not performing adequately when needed.
- Due to inherent battery system design there is no cost effective method to determine exactly when this probability becomes unacceptable. An assumption of 20 years, based on well founded industry data is the most cost effective way to ensure that all battery systems on the network are adequate.
- At all locations, a battery system that does not perform adequately could result in serious safety, reliability and financial consequences.

METRICS TO TRACK BENEFIT(s):

The success of this project will be measured by a reduction in the number of battery systems over 20 years old remaining on the system.

COSTS AND AVOIDED COSTS:

A planned replacement approach will avoid the additional costs associated with the emergency replacement or repair of battery systems. The ongoing substation inspection & maintenance requirements will not change as a result of this strategy.

EXHIBIT 17

PROGRAM NAME:

Shield Wire Replacement Program

PROGRAM DESCRIPTION:

This major program concerns the replacement of shield wire on 408 miles of 115 kV transmission lines or approximately 9% of the total 115 kV mileage in The Company's New York System. The replacement of this shield wire will improve the availability of The Company's New York Transmission System by over 2,000 minutes/year. Also, it will reduce the possibility of safety incidents to the general public in the case of unnoticed shield wire failures.

The scope of this program includes replacing the shield wire on the transmission lines listed below in Table 1 with high strength steel. This list is based on circuits with the highest priority scores. The majority of the considered lines are in the Frontier region. This is consistent with shield wire failure outages and shield wire maintenance projects have been occurring in The Company's New York System. This list may be amended as results from preliminary engineering and further condition data are obtained and circumstances warrant.

Table 1 – NY 115 kV Prioritized Circuits for Shield Wire Replacement

115 kV Transmission Circuit	Region	Age (years)	Distance (miles)
Huntley – Gardenville 38/39	Frontier	74	28.7
Lockport – Mortimer 111	Genesee	75	66.4
LaFarge Building Materials – Pleasant Valley 8	Capital	65	62.5
Gardenville – Homer Hill 151/152*	Frontier	84	82.6
Huntley – Praxair 46/47	Frontier	39	9.8
Mountain – Lockport 103	Frontier	74	19.9
Niagara – Gardenville 180	Frontier	74	31.7
Gardenville – Depew 54	Frontier	51	7.3
Huntley – Lockport 36/37	Frontier	62	22.1

Clay – Dewitt 3	Capital	58	20.5
Gardenville – Buffalo River Switch 145/146	Frontier	45	12.6
DuPont – Packard 183/184	Frontier	48	4.5
Gardenville – Dunkirk 141/142	Frontier	78	56.7
Walck Road – Huntley 133	Frontier	32	10.4
South Oswego – Nile Mile Unit One 1	Capital	66	13.0

**The shield wire on the last 20 miles of these lines (north end) is already being replaced under a separate project, therefore only the remaining shield wire will be replaced.*

The scope also includes a review and upgrade, as necessary, of the grounding system on each structure.

DRIVERS:

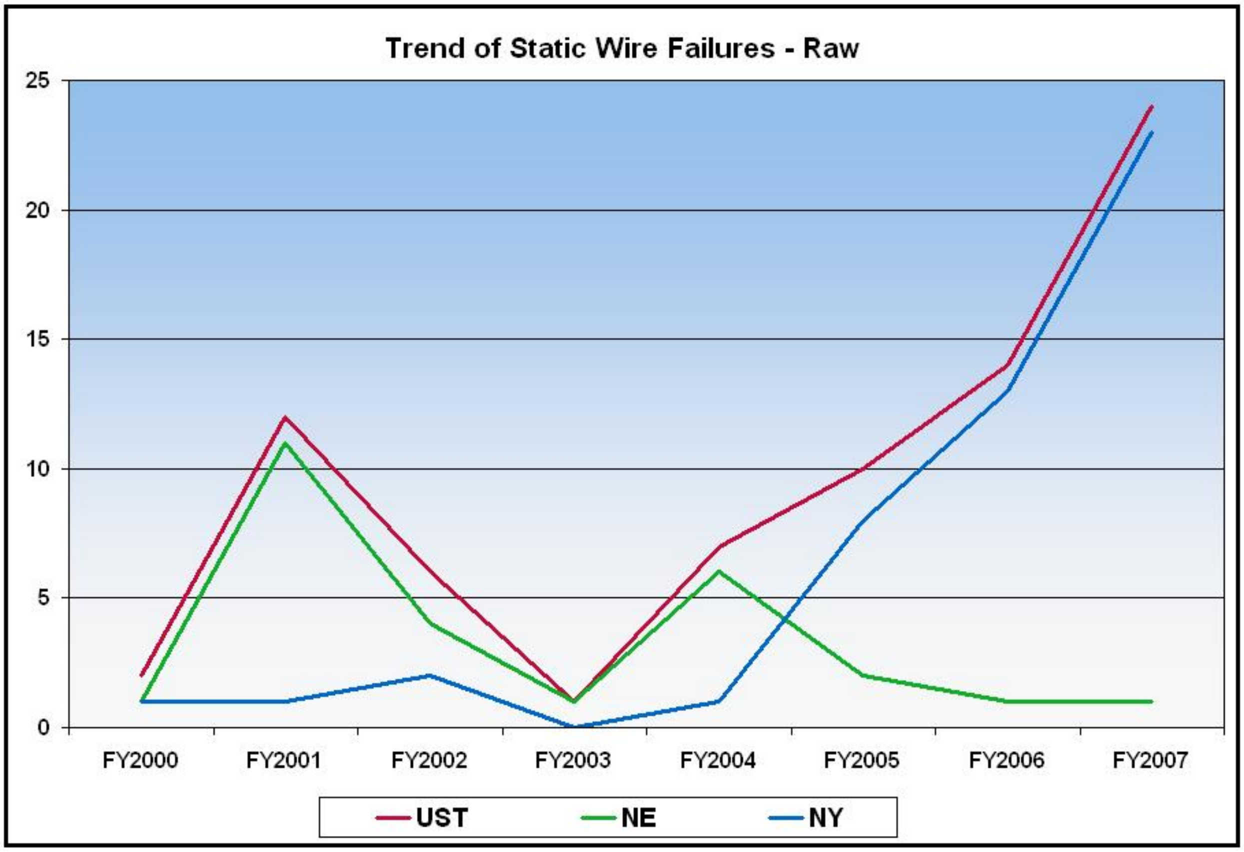
The shield wire, or often referred to as the static wire, plays a critical role in the stability of a transmission circuit. The shield wire serves both a mechanical and electrical function on a transmission system. On the majority of 230 kV and above lines the shield wire system is composed of two wires made of high strength steel. The 115 kV and below lines utilize a single wire.

The shield wire is a critical element in the grounding of the high voltage transmission system. During lightning strikes, the shield wire serves as a grounding element shielding the lightning strikes away from energized conductors and conveying it to ground without permitting flashover to occur. If installed properly, a well grounded shield wire system significantly reduces the likelihood of an outage due to a lightning strike.

In addition to lightning protection, the shield wire provides critical support against the imbalance of forces in the longitudinal direction. These imbalances occur more often than suspected and as long as the shield wire system is intact, they go unnoticed. These forces can be caused by heavy wind, conductor drop or failure, splice failure, localized wind shear, ice loading (or unloading), structure tilt due to foundation failure or component failure, etc. An intact sound shield wire will help minimize structural related outages.

Safety is also a major factor when dealing with shield wires. A dropped shield wire that goes unnoticed (no outage) creates a major safety concern to the public. There have been instances of this in the past. In one instance the adjoining land owner coiled the shield wire and attached it to the leg of a 115 kV lattice tower with the line still energized.

As part of The Company's asset management program, reliability is monitored regularly. In recent years, there has been a spike in shield wire related outages, with most of them occurring in the 115 kV transmission "class" (*see figure below)*. Approximately 40% of the shield wire in this class is over 70 years old, which is above the expected asset life of 50 years (as determined by the CIGRE working group 37-27[122]).



OTHER ALTERATIVES CONSIDERED:

Option 1: Do nothing. This is not recommended due to the fact that shield wire failure outages and unnoticed dropped shield wire is an increasing problem on The Company's New York transmission system. This does not only negatively impact reliability, but more importantly, it creates a major safety hazard to the general public.

Option 2: Remove all the shield wire identified in Table 1 and leave these circuits without shield wire until they are scheduled to be replaced over the next five years. Even

[122] CIGRE (International Council on Large Electric Systems) working group 37.27 is a technical workgroup made of individuals from different international utilities. The full report produced by this working group can be found in Attachment 4.

though the benefit of this option is that it leaves no possibility that any of the old shield wire identified in Table 1 will drop and go unnoticed (therefore eliminating any hazard to the general public), this option is not recommended because these circuits will be directly exposed to lightning strikes and negatively effect the reliability performance of these circuits until the shield wire is replaced

CUSTOMER BENEFITS OF PROGRAM:

The planned program targets reliability improvements of the 115 kV transmission class by reducing the total duration of sustained outages in The Company's New York system by over 2,000 minutes/year. This will be accomplished by replacing approximately 408 miles of the shield wire system in the class. This equates to approximately 9% of all the shield wire in the NY 115 kV class.

The benefit to the customer is in the enhanced reliability of the transmission system. In FY07, shield wire failure accounted for approximately 6% of the total duration of sustained outages. This program is expected to reduce this number by at least 20% which will result in a reduction of over 2,000 minutes/year to the total sustained outage durations.

There will also be a benefit in the improvement in the safety performance of each circuit. Shield wire failure is a monthly occurrence. Some go unnoticed to the customer. Most result in an outage. In FY2007 alone, there were 23 static wire failure outages. Even those that go unnoticed generally require a scheduled outage for repairs. Consequently, the reliability of the circuit suffers as do those customers served.

A very dangerous situation is created when a shield wire fails and does not trip the circuit. While this is not common it does happen. One such event has been described previously in this document. There are others events, with the most recent being in the Frontier region when a downed shield wire was coiled up and placed at the base of a tower with the line still energized.

The replacement of the shield wire system on those lines listed will improve the reliability of and reduce significantly the risk of a safety event due to shield wire failure.

Shield wire failures can have a detrimental impact on the operation of the transmission grid. Delaying replacement will increase the risk of failures and along with it the potential of a safety event as well as degradation in reliability.

METRICS TO TRACK BENEFITS:

The shield wire replacement program offers The Company the opportunity to improve the reliability performance of the transmission network. Reliability improvements will be measured by the following indices:

- SAIFI: System Average Interruption Frequency Index
- SAIDI: System average Interruption Duration Index
- CAIDI: Customer Average Interruption Duration Index

COSTS AND AVOIDED COSTS:

As a result of this work, a potential OPEX saving may be realized due to a reduction in trouble maintenance.

Currently, momentary disturbances on The Company's New York system are not patrolled; therefore, there is no OPEX saving to be gained as a result of a reduction in disturbance patrols of momentary disturbances caused by shield wire failures. However, sustained disturbances require OPEX expenditure to patrol and restore the system. The proposed circuits which will have their shield wire replaced have had, on average, a total of 5 sustained disturbances per year caused by shield wire failures. Each of these sustained disturbances results in an estimated OPEX expenditure of $1000/disturbance. Therefore a potential saving of $5,000/year may be realized due to a reduction of sustained disturbances caused by shield wire failure.

The shield wire on the proposed circuits is scheduled to be finalized the next 2-3 years; the work was originally started in CY2008. Therefore the complete $5,000/year OPEX savings will not be realized in about 3 years from now if all 400 miles was completed. However, some static wire will not be replaced right away as originally planned. The Packard-Urban 181 (about 23 miles) and the Gardenville-Homer Hill 151-152 (south, about 55 miles) will not be replaced. The 181 will be replaced in its entirety by the Frontier Project and engineering field walk-down for the 151-152 lines indicate that the static wire is in good enough shape until the planned refurbishment in 3-5 years. Thus only 80% of the original savings is anticipated, or $4,000, which would be an <u>average</u> savings.

While a reduction in trouble maintenance is anticipated in the targeted static wire replacements by the strategy – other static wire on the system continues to age. Increases in static wire failures on these circuits could increase wiping out these projected savings.

The replacement of the identified shield wire will not result in any savings associated with a reduction in planned preventive maintenance since there is no preventive maintenance program specifically aimed at shield wires. Rather, the line maintenance programs focus on all transmission line components and thus they would be continued to be performed according to their schedule.

EXHIBIT 18

PROGRAM NAME:

Steel Tower Strategy

PROGRAM DESCRIPTION:

Tower Painting and Structure Replacement Program

DRIVER(s):

The New York Public Service Commission Order per Case 04-M-0159 (effective January 5, 2005) directed Niagara Mohawk to ensure that the Company's transmission lines meet the governing National Electric Safety Code (NESC) under which they were built. The order instructed the Company to replace wood poles and structures that no longer meet the governing code requirements.

There are 20,325 steel structures (17,448 towers and 2,877 poles), 35,703 wood poles, and many steel and concrete foundations in service across Niagara Mohawk's service territory.

At the time the strategy (SG018) was written, four failures of steel structures on the New York Transmission system attributable to poor condition were identified.

- April 2003: a tower on the Pannell-Geneva 4-4A 115kV Line in Western NY toppled during an ice storm. Deterioration at the base of the tower contributed to this failure.
- September 2003: The Company replaced a deteriorated steel tower on the 115 kV Gardenville-Homer Hill 151-152 transmission line.
- February 2004: a line mechanic climbing on a tower on the Niagara-Gardenville 180 line partly fell when a corroded steel support gave way.
- June 2004: the 115kV Gardenville-Homer Hill 151 line, tripped and locked out due to failed cross arms on two towers.

Since the strategy was written the following failure has occurred:

- March 2009: the T2240 GE–Geres Lock 8 115 kV circuit tripped and locked out due to the failure of tower #435. Tower #435 is a square based steel lattice tangent suspension tower. The tower was located in a detention pond at a former chemical manufacturing plant. The failed tower was in approximately four feet of water. Due to the deep water, the base of the tower could not be removed for examination. This limited the ability of foot patrols to conduct routine inspections and footer repairs.

The failed tower was replaced with a wood pole structure. Failure Analysis FA0033, dated March 2009, recommended that the condition of the remaining towers in the detention pond should be inspected for damage and repaired accordingly.

Steel structures are categorized into 6 different visual grades, as follows:

DESCRIPTION	VISUAL GRADE
Fully painted- overcoat and undercoat intact fully galvanized – coating intact	1
Paint coating over all surfaces – overcoat may not be intact and some very small areas (<1%) of light corrosion may be present. Galvanizing intact except for some very small areas (<1%) of light corrosion.	2
Very light surface corrosion, majority of coating intact	3
Light pitting – possibly some very light edge roughening. Loss of greater majority of coating and zinc layers. Corroded surface would dominate surface preparation.	4
Significant pitting – loss of section clearly visible, edges feathered/thinned.	5
Perforated element – severe physical damage	6

Table 1

Generally, Visual Grade 4 Structures still retain most of the structural strength because the rust is predominately surface. However, it is not unexpected for many of the Visual Grade 6 structures to have more than a 15% strength loss. Consequently, these structures will not meet the original NESC loading criteria under which they were designed. Visual Grade 5 structures reside somewhere in between Visual Grade 4s and 6s in structure capability. Though they might still meet NESC loading requirements, permanent structural damage has occurred due to a visible loss of section.

Complete removal of the rust from a Visual Grade 4 steel structure by sandblasting followed by priming and painting will adequately restore a steel structure in most cases. Under most conditions, the application of high quality paint will protect the structure from rusting for 15-20 years. As sandblasting is a time consuming practice, it generally is costly. Compelling, though not conclusive, indications exist implying that the wire brushing of Visual Grade 4 to remove loose rust combined with zinc rich primers and paints will extend the life of a structure by 10-20 years. Subsequent follow-up painting might further extend the life of these structures.

Structures are now evaluated and graded during the five year foot patrol cycle through visual, on-site inspections. The grading criteria are provided in

Visual Grade	Number of Assets	Percentage
1	8,689	49.61%
2	3,396	19.39%
3	3,703	21.14%
4	1,339	7.65%
5	380	2.17%
6	6	0.03%
Total	17,513	100.00%

Table 2. This field practice was initiated in 2006. Based on an August 2009 Computapole extract, the distribution of visual grading was as follows:

Visual Grade	Number of Assets	Percentage
1	8,689	49.61%
2	3,396	19.39%
3	3,703	21.14%
4	1,339	7.65%
5	380	2.17%
6	6	0.03%
Total	17,513	100.00%

Table 2

OTHER ALTERNATIVES CONSIDERED:

Option 1 (Do nothing): Delay refurbishment projects until failure occurs due to continued deterioration. This option would place the Company in breach of the Public Service Commission Order (Case 04-M-0159) to adhere to standards set out in the National Electric Safety Code. By selecting this option structures would continue to deteriorate, posing increasing risk to the public safety and to a lesser extent reliability (It should be noted that circuits could be out for extended periods of time when failures do eventually occur).

Option 2 (Refurbishment of High Risk Lines): Refurbishment will be needed for the high risk lines. The refurbishment program over several years in which structures with a visual Grade of 4 or worse are replaced. For efficiency purposes, other deteriorated components on the steel tower line may be replaced, as deemed necessary by the engineering field condition evaluation.

Reason for Rejection: This option replaces assets sooner that the point nearing “end of life” and may be more costly than needed.

Option 3 (Refurbishment of High Risk Lines (keep Visual Grade 4 structures):

A variation of 2, this also assumes a level of refurbishment will be needed for the high risk lines consistent with the original strategy assessment. Structures with a visual Grade of 5 or worse are replaced. Visual Grade 4 structures (in general) will not be replaced. Visual Grade 4 structures with “sound rust” would be painted using a penetrating, primer, and finishing coat. However, Grade 4 structures located near roadways, railways, or navigable waterways would still be replaced. For efficiency purposes, other deteriorated components on the steel tower line may be replaced, as deemed necessary by the engineering field condition evaluation.

Reason for Rejection: This option was the original option followed until approval of the Overhead Line Refurbishment Strategy.

Option 4 (Replace only those steel structures and components no longer meeting the governing NESC code): Structures with a Visual Grade of 5 or worse are replaced. Visual Grade 4 structures will in general not be replaced (even those near roadways, railways, or navigable waterway). This program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built by replacing wood poles and structures that no longer meet the governing code requirements. This follows standard industry practice and the Public Service Commission Order per Case 04-M-0159 effective January 5, 2005 to adhere to the NESC.

Reason for Rejection: While evidence indicates that the painting of structures with a Visual Grade of 4 will extend the life of these structures a number of years, this is not definitive. The additional safety risk near roadways, railways, or navigable waterway was felt to be sufficient enough to take the additional precaution and replace these steel structures. For efficiency purposes, other deteriorated components on the steel tower line may be replaced, as deemed necessary by the engineering field condition evaluation.

Option 5 (Coordinate Refurbishments with SG080 (recommended):

Transmission lines with no planed refurbishments under SG080 would be refurbished under this strategy (following a field evaluation of the condition). If an SG080 type refurbishment is more than 3-5 years away or requires an Article VII filing, a safety type refurbishment may be pursued to replace the structurally unsound structures that do not adhere to the governing NESC standard under which they were built. Visual Grade of 5 (or worse) structures would be replaced. Visual Grade 4 structures (in general) would not be replaced. Visual Grade 4 structures with “sound rust” would be painted using a penetrating, primer, and finish coat. However, Grade 4 structures located near roadways, railways, or navigable waterways would still be replaced. For efficiency purposes, other deteriorated components on the steel tower line may be replaced, as deemed necessary by the engineering field condition evaluation.

CUSTOMER BENEFIT(s) OF PROGRAM:

Public safety is one of the key benefits of pursuing Option 5. First of all, by replacing deteriorated structures adjacent to roads, railroads, and navigable waterways, safety is enhanced. Secondly, by replacing other structures (those not near crossings) the remaining safety concerns caused by deteriorating structures are addressed.

The Overhead Line Refurbishment Strategy (SG080) was approved in March 2008, effectively modifying the Steel Tower strategy to follow Option 4. The present phase of the

Overhead Line Refurbishment Strategy focuses primarily on refurbishing circuits that fall within the 40 worst performing circuits. SG080 will absorb longer-term steel tower replacement projects that might have been previously planned under SG018. In addition to improving safety, SG080 seeks reliability improvements.

If the Visual Grade 4 structures with "sound rust" are painted using a quality priming system and finishing coat, it is not unreasonable to expect that their life could be extended by 10 years. With additional maintenance painting every 15 -20 years, it is conceivable some of them could last beyond that.

With a limited or restrained capital budget, painting Visual Category 4 structures makes sense. Considerably more structures can be done for a comparable budget. This approach optimizes the limited capital budget funds available provided expense funding can be made available.

Painting materials offer a greater flexibility if circumstances dictate a given transmission line cannot be taken out of service right away. Painting materials can readily be shifted to another transmission line requiring painting. This is more difficult to do with structural replacement components deployed at the transmission site.

In remote areas, it is easier to get painting materials to the site than it would be to get a new structure to the same site.

From a customer viewpoint, painting is the best option for keeping electric rates down.

METRICS TO TRACK BENEFIT(s):

As structures continue to be evaluated during the five year foot patrol cycle through visual inspection on-site and graded according to the criteria provided in Table 1, a shift should occur so that the number of Visual Category 5 and 6 structures will approach 0. Visual Category 5 and 6 structures generally no longer meet the safety design codes under which they were built. In addition, the number of Visual Category 4 structures should be reduced as these structures are serviced and painted.

A reduction in the amount of steel tower failures should become apparent (five have been experienced since 2003). While this might not have a significant reliability impact, it certainly does pose a safety risk to the public.

COSTS AND AVOIDED COSTS:

Strategy SG018 Version 2 initially concentrated on critical crossings. Based on engineering field walk-downs conducted by Transmission Line Engineering, Project Funding Order C04636 resulted in a total of 171 structures being replaced throughout upstate New York. These replacements were done in calendar years 2006 through 2009. In addition to the replacements indicated in Table III-15, the South Oswego-Lighthouse Hill project scope includes 38 structure replacements, some of which are critical crossing structures. Due to outage constraints on these lines, replacement of the critical crossing structures was combined with project C21693 (Interim measures were taken to temporarily reinforce and secure these towers.).

The following table shows active refurbishment projects that are tied back to the Steel Tower Strategy (SG018)

Project Number	Driver or Strategy	Title18	Projected Construction FY
C21376	SG018	Packard-Urban 181 T1850 STR	FY2009/10
C21692	SG018	Niagara-Packard 191 STR	Cancelled
C21693	SG018	S Oswego -Lighthouse Hill Circuits T2630-T2300-T2220-T2610	FY2010/11
C27431	SG018	Lockport-Batavia 108 T1500 STR	TBD
C27432	SG018	Lockport 103-104 T1620-T1060 STR	TBD

Table 3

Funding Project C21692 was cancelled following a ground based engineering field walk down of the Niagara-Packard 191 line. The steel towers were found to be in good structural condition. Additional projects are planned for initiation over the next five to ten years. Costs of these projects have yet to be determined.

The OPEX savings from the replacement of towers nearing end of design life mainly is anticipated to come from decreased planned preventive maintenance. No significant reductions in trouble calls are anticipated.

At this point the anticipated savings are conceptual in nature. It looks at the typical savings over the next 4 years plus this FY.

Decreased Planned Preventive Maintenance

Originally, the OPEX assumed that 175 structures were to be replaced already due to the steel tower program. However, the OHL Refurbishment program is picking up a significant portion of the steel tower strategy. Now assuming 25 structures will be replaced per year over the next two years. This would yield a total of 100 new structures over the next 4 years.

An initial savings on painting, footer inspection & repairs, and ground-line treatment is expected. Consistent with paragraph 19 in Strategy SG052, approved on 24 Feb 2006, the new steel structures will not be painted or the footers repaired during the first painting and footer inspection & repair cycle after installation. Ground-line inspections and treatments generally do not occur for the first 20 years and painting is in a 15 year cycle.

	Per Structure	Years	Annual (ave)
Painting	2,600	15	$173

Footer	1800	20	90

Table 4

Painting

Steel Poles & Towers: 175 done

Projected Savings: 175 × \$173 ≈ \$30,000 per year

Steel Poles & Towers: 25 per year

Projected Savings: 25 × \$173 ≈ \$4,500 per year

Footer Inspections & Repairs

Steel Poles & Towers: 175 done

Projected Savings: 175 × \$90 ≈ \$16,000 per year

Steel Poles & Towers: 25 per year

Projected Savings: 25 × \$90 ≈ \$2,000 per year

There is no OPEX savings related to trouble or emergency work because the numbers of tower failures is small and when failures occur they result in capital investment.

The Company reinstated the painting program after the acquisition of Niagara Mohawk. Although towers have been painted throughout their lives, this OPEX program had been discontinued by Niagara Mohawk for a number of years prior to the acquisition. Therefore, this is not included as an OPEX savings to the base program.

The footer inspection & repair did exist at the time of the acquisition and so these savings are included in the chart below.

The average incremental maintenance spending over the next 4 years is estimated to be reduced by:

	FY2010/11	FY2011/12	FY2012/13	FY2013/14	FY2014/15
Total (Approx.)	\$16,000	\$18,000	\$20,000	\$22,000	\$24,000

EXHIBIT 19

PROGRAM NAME:

Substation Rebuilds, including: Gardenville, Dunkirk and Rome

PROGRAM DESCRIPTION:

Rebuilding or upgrading Transmission Substations

There are three stations currently being closely studied in The Company's New York service area for either upgrades or rebuilds to better meet the current and future needs of the transmission system and its users. Gardenville (230/115kV), Dunkirk (230/115kV), and Rome (115kV) have been identified as having asset condition and/or configuration issues that will result in the need for a major station rebuild or upgrade.[123] These stations have undergone condition assessments and are at various stages of engineering, leading towards a planned rebuild of some degree.[124]

Strategy SG 112 has been approved for the construction of a completely new 115kV substation within the Gardenville complex and preliminary engineering has commenced. The new station will be located in the Old Gardenville section, north of the existing 115kV substation. Once completed, the new substation will completely replace the 115kV section of Old and New Gardenville which will be retired and removed. The 230kV yard and 230-115kV Transformers will remain at the New Gardenville section with connections to the new substation.

A new control building will be built to accommodate the new substation. The existing New Gardenville control building will be used only for the 230kV switchyard and 230-115kV Transformers. All unused equipment in this building will be removed. The existing control building at Old Gardenville will be removed.

The new Gardenville substation will be in a switch-and-a-half arrangement. This will address all station configuration issues and significantly reduce exposure, especially during contingencies. In addition, this arrangement will make equipment outages much easier and less costly to obtain. The proposed arrangement calls for construction and completion of the new switchyard while the existing one remains in service. Once complete, lines will be

[123] Further details are provided in "Report on the Condition of Physical Elements of Transmission and Distribution Systems," October 1, 2008, Exhibit 2, p. V-66 (Upstate NY Asset Health Report for Transmission. at p. 62, section 6.8.2). Further details are provided in "Report on the Condition of Physical Elements of Transmission and Distribution Systems," October 1, 2009, Page III-68.

[124] New Scotland, which had been identified as having possible configuration issues, has been dropped from consideration for a major rebuild. The most recent NERC N-1-1 studies have indicated that the configuration of New Scotland is adequate and poses no major problems; in addition there are no urgent asset condition issues. Lockport, Lighthouse Hill and Rotterdam stations are discussed in a separate justification document in this filing (Exhibit 20) because they are not as far along in their conceptual engineering.

transferred to the new switchyard with minimum outage time. The proposed arrangement will seek to eliminate all line crossovers.

For the Dunkirk station, a project has been approved to install a new cable trench in the 230kV yard in 2009. Control cables deemed faulty can be replaced using these new facilities. In the long term, conceptual engineering is underway to construct a new control house and completely separate assets in this station. Any current cable trench work will be used with this new control house. In addition, other equipment, such as disconnects and power transformers deemed to be at end of life will be replaced during a project to install a second bus tie.

For the Rome station, a strategy paper is under development proposing a station rebuild beginning in calendar year 2010. Conceptual engineering for this solution includes moving the South bus capacitor bank, building a new control house and new north bus, relocating 115kV lines such that Rome - Oneida #1 and Levitt - Rome #8 terminate at the south bus and Boonville - Rome #3 and Boonville - Rome #4 terminate at the north bus, replacing assets deemed in poor condition in the south yard, and adding a line bypass switch between the Levitt-Rome #8 and Rome-Oneida #1 lines to reduce line outages due to substation faults or planned maintenance at the station.

DRIVERS:

Gardenville station is a 230/115kV complex south of the Buffalo area in western New York. It has two 115kV stations in close proximity referred to respectively as New Gardenville and Old Gardenville, both serving regional load. New Gardenville was built between 1959 and 1969 and has some minor to moderate asset issues. Old Gardenville feeds regional load via eleven 115kV lines. The station, built in the 1930s, has serious asset health issues including, but not limited to: control cable, breaker, disconnect and foundation problems. The station has had no major updates since it was built. There have been mis-operations that can be directly attributed to control cable issues in the past several years (illustrated below in Table I).

Table I - Gardenville Historical Outages (excluding line related outages)

DATE	COMPONENT	NOTE
01/07/2003	#180 Line	CB failed to reclose, bad wiring
05/06/2003	Bus 6 & 8 (#54, 81, 82, 39, 45, 180 Lines)	Bus trip, bad wiring
11/09/2005	#141 Line	CB failed to reclose, CB trouble
11/28/2005	#151 Line	Line Trip, bad BPD
01/04/2006	#180 Line	Line trip, bad wiring
01/10/2006	Bus 6 & 8 (#54, 81, 82, 39, 45, 180 Lines)	Bus trip, bad wiring
03/13/2006	#141 Line	CB failed to reclose, bad wiring
09/01/2006	#141 Line	CB failed to reclose, relay trouble
09/10/2006	#141 Line	CB failed to reclose, relay trouble
10/15/2006	Bus 5 & 7 (#141, 38, 182, 44, 82 Lines)	Bus trip, bad wiring
12/01/2006	Bus 5 & 7 (#141, 38, 182, 44, 82 Lines)	Bus trip, bad wiring
05/07/2007	#180 Line	CB failed to reclose, relay trouble

05/11/2007	#54 Line	CB internal damage
07/06/2007	Bus 5 & 7 (#141, 38, 182, 44, 82 Lines)	Bus trip, bad wiring
12/27/2007	#180 Line	Line trip, bad wiring
03/18/2008	Bus 5 & 7 (#141, 38, 182, 44, 82 Lines)	Bus trip, bad wiring

Dunkirk Station is a joint substation shared at Dunkirk Steam Station (Coal generation plant) by NRG and The Company. The substation serves as an interconnection to the electrical grid at the 230, 115 & 34.5kV levels. The plant was originally constructed in the early 1950s by Niagara Mohawk as the owner of generation, transmission and distribution assets. The Company's major equipment includes four transformers: two new 230/120/13.2kV 125 MVA autotransformers and two 115/34.5kV 41.7 MVA transformers feeding four 230kV, five 115kV and two 34.5kV lines as well as NRG's station service. The Company retains ownership of most of the 230kV and 115kV switch yard. However, the controls are located in the generation control room owned by NRG.

There are many asset condition issues at the Dunkirk substation. The foundations are in poor condition in the 230kV yard, including many structure foundations, affecting the integrity of the structure itself. See Figure I below.

Figure I - 230kV Structure Foundation at Dunkirk

Some circuit breaker foundations are in very poor condition raising the possibility that an oil circuit breaker (OCB) could move during a severe fault leading to more damage and/or cause safety issues.

The five 230kV oil circuit breakers are of vintage Westinghouse design (1958 through 1961) and have reached the end of their useful life. The 230kV Westinghouse Type O bushings are a concern as the power factor and capacitance results are trending upwards.

The 230/120/13.2kV autotransformers differential relaying is in need of upgrading to address inadequate relaying (presently there is no tertiary differential). The 230, 115 & 34.5kV disconnects have become more problematic and are at the end of their life. The 230kV bushing potential devices (BPDs) have become problematic as they are aging and the remaining BPDs will likely have to be replaced in the near future. Fencing around the yard is not compliant with The Company standards and requires repair at the base or a berm built up to prevent animal entrance.

The control cable system in the 230kV yard is of particular concern. It is clear that the conduit system carrying control wires has degraded to the point that the integrity of the control wires has been compromised. Control wires inside the plant have also seen insulation degradation. In some cases, the wiring is so poor that troubleshooting abilities are limited for fear of handling control wires with degraded insulation. Grounds, alarms or breaker mis-operations happen more frequently during periods of heavy rain, indicating poor insulation below ground.

Table II - Outage Information (230 kV)

COMPONENT	DATE	NOTE
Gardenville - Dunkirk Line #74	10/3/05	Line #74 opened at Dunkirk end only when Dunkirk Bus 30 cleared. Buffalo Relay Department found wiring problems in the CT circuit for TB#31
Gardenville - Dunkirk Line #74	5/16/06	Line operated when the Dunkirk #30 bus cleared. Bus 30 cleared due to several circuit grounds due to bad wiring.
Dunkirk - South Ripley Line #68, Gardenville - Dunkirk Line #73	5/19/06	Dunkirk Station 230 kV Bus 40 cleared resulting in the outage. The cause of the bus clearing was a ground on the CT wiring for bus-tie breaker R1312

Table III - Outage Information (115 kV)

COMPONENT	DATE	NOTE
Dunkirk - Falconer Line #160 Dunkirk - Falconer Line #162 Gardenville – Dunkirk Line #141	10/19/06	CB R252 opened; reclosed manually. The cause of the bus clearing was an error made by the technicians working for NRG (generator) who were conducting the testing

The plant was originally constructed with generation and transmission distribution assets combined including station service, battery, relaying, alarm / annunciation, control and communications. All troubleshooting, maintenance testing, equipment replacement and upgrades require excellent knowledge of the plant operation. NRG and The Company must maintain good lines of communication and shared updated prints to preserve operation continuance. The separation of assets would help avoid inadvertent trips to the generators and / or line breakers or any possible equipment failures.

The Rome Station is an original station within the The Company system built in the early 1920s. It has received several reconfigurations over the years with the current 115kV to 13.2kV dual bus built in the early 1970s. The station is separated into north and south sections with a tie-breaker connection between the two. The 115kV north and south busses each have two connecting transmission lines and associated grounding banks installed in 2003 to improve transmission system protection. The south bus also contains a 115kV capacitor bank. Each bus has a 115kV, 30 MVA transformer that steps down to a 13.2kV metal clad switchgear and supplies local distribution feeders for the city of Rome.

The 115kV system at the Rome Station experiences periods of low voltage, particularly if the tie-breaker is opened. The latest station condition assessment performed 10/16/2008 revealed significant asset health concerns including: the 115kV disconnects being degraded and often breaking upon operation, 115kV instrument transformers built in the 1930s that have heavily weakened foundations, failing batteries and chargers during bus outages, the control house has asbestos and deteriorated windows and doors and the steel structure on the North bus is heavily corroded with degraded footers illustrated in Figure II below.

Figure II - Rome Station Structures and Foundations are Severely Deteriorated

The 115 kV radial Levitt-Rome #8 line feeds approximately 100 MW of load in the surrounding area and has had several outages resulting in lost customer minutes due to slow closing breakers (which in prior condition assessments have been noted to have rusting and compressor oil leaks).

Furthermore, station property near the north bus section has been under environmental remediation the past several years due to a former coke plant at the site that produced natural gas which ultimately contaminated the site. Moving assets currently located in the North yard further from the site remediation and Mohawk River side of the yard would reduce the Company's exposure to involving them in future environmental clean-up plans.

ALTERNATIVES CONSIDERED:

Speaking collectively for the three stations, two other options to the recommended station rebuilds exist.

Option 1 – Replace components after failure. While there are adequate spares in the system to replace breaker and transformer failures that may occur at these three substations, given the consequences and costs associated with damage/ failure, this approach is not recommended. Furthermore, this does nothing to resolve less than ideal station configurations which currently exist.

Option 2 – Deferral. This option is not acceptable given the current asset condition of the three stations. Reliability, already at low levels, will continue to degrade as assets in poor condition continue to deteriorate.

CUSTOMER BENEFITS of PROGRAM:

The planned replacement of these three stations reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

Implementing this program would also address the need for reliable fault interruption capability for the safety of Company employees and its equipment. In addition, as planned replacements are less costly and more efficient than unplanned replacements (failure), therefore offering the lowest lifetime cost approach for customers.

METRICS TO TRACK BENEFIT(s):

The success of these substation upgrade projects will be shown by an increase in the reliability of the upstate New York transmission system as seen by our customers.

The circuit breaker replacement strategy offers The Company the opportunity to improve the reliability performance of the transmission network. Reliability improvements will be measured by the following indices:

- SAIFI: System Average Interruption Frequency Index
- SAIDI: System average Interruption Duration Index
- CAIDI: Customer Average Interruption Duration Index

COSTS AND AVOIDED COSTS:

In instances of station rebuilds, as those proposed above for Gardenville, Dunkirk and Rome, assets are generally replaced on a one-for-one basis often resulting in the same number of assets in the new station as were in the old. Exceptions of course happen when reconfigurations are made from a single breaker to a breaker-and-a-half scheme for example, which increases the number of assets. Typical station rebuilds due to asset condition will not result in a decreased spending in preventative maintenance. However, we would expect a reduction in trouble maintenance expenses once normal 'teething problems' associated with new equipment are corrected.

These new assets will still need all the preventative maintenance of the ones they have replaced. Visual and operational inspections, mechanism tests, diagnostic tests, and dissolved gas analyses for transformers would all still need to be performed.

Furthermore, the circuit breaker and transformer replacement programs also discussed in this filing will offer potential areas for cost savings based on the number and location of strategic spares they create. For example, it would be financially beneficial if the entire population of breakers could be supported by a single, centrally held spare. However, all of these potential OPEX benefits for these three station rebuilds have yet to be fully explored and it would not be prudent to forecast cost savings at this point.

EXHIBIT 20

PROGRAM NAME:

Substation Rebuilds, including Rotterdam, Lockport and Lighthouse Hill

PROGRAM DESCRIPTION:

Rebuilding or upgrading Transmission Substations

There are three stations currently being considered in The Company's New York service area for either upgrade or rebuild to better meet the current and future needs of the transmission system and its users. Rotterdam (230/115/13.2kV), Lockport (115/12kV), and Lighthouse Hill (115/12kV) have been identified as having asset condition and/or configuration issues that will result in the need for a major station rebuild or upgrade.[125] These stations have undergone condition assessments and are at various stages of engineering toward a planned rebuild of some degree.[126]

DRIVERS:

Rotterdam is a large station with 230kV, 115kV, 69kV, 34.5kV, and 13.2kV sections spread out over multiple tiers on a hillside. The 230kV yard is the main source for Schenectady, NY, getting its feeds from Porter Lines #30 and #31 and from Bear Swamp on the E205 line to Massachusetts. The 230kV yard has had performance issues and one catastrophic failure of a Federal Pacific Electric ("FPE") breaker. These breakers, pictured in Figure I below, have horizontal rotational contacts inside their tank as compared to vertical lift contacts in other style breakers. FPE breakers are no longer manufactured and spare parts are not available. These breakers will be replaced as part of a major replacement program.

[125] Further details are provided in "Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878" October 1, 2009, Page III-73.
[126] New Scotland, which had been identified as having possible configuration issues, has been dropped from consideration for a major rebuild. The most recent NERC N-1-1 studies have indicated that the configuration of New Scotland is adequate and poses no major problems; in addition there are no urgent asset condition issues. Gardenville, Dunkirk and Rome stations are discussed in a separate justification document in this filing Exhibit 19 because they are further along in their conceptual engineering.

Figure I

Federal Pacific Breakers at Rotterdam are the only ones left on the System

Two of the three 230kV auto transformers are also proposed for replacement. The #7 and #8 transformers have a higher than normal failure mode due to their design specifically due to T beam heating and static electrification.

There has been an issue with capacitor bank #4 tripping off line on differential if capacitor bank #3 is put into service while capacitor bank #4 is on line. This does not happen for the reverse scenario. Capacitor bank #3 does not trip if in service when capacitor bank #4 is added to the system.

All of the Thyrite (Silicon Carbide) style surge arrestors on the 230kV system should be replaced with the newer MCOV (Metal Oxide) style arresters.

Most of the 115kV breakers and disconnect switches are nearing end of useful life. Many have had problems in the past with breaking and not operating correctly. The concrete foundations supporting the breakers and structures, the differential, and voltage supply cabinets are all in very bad shape and require repair or replacement. Some need attention now and others within the next 5 years.

Given the extent of the asset condition issues discussed above and the need for upgrades at the station due to the Northeast Region Reinforcement Project (Luther Forest) as outlined in Appendix 1, page 13 of the Company's Petition to Defer Electric Transmission and Distribution Investment Costs (Case 07-E-1533 filed April 21, 2009), the Rotterdam substation is a candidate for rebuilding, making it a modern and more reliable network station in a very important transmission corridor.

Lockport is a major 115KV transmission station with thirteen 115 kV transmission lines tying through the East and West bus sections. This station is critical to the 115 kV system operations of Western New York. The overall condition of the station yard and control room is poor. Work is required on control cable duct banks, breaker operators, structure painting and concrete equipment foundations that are deteriorated significantly.[127]

The structures are severely rusted and in need of painting before the steel is compromised. Figure II illustrates the typical steel condition at the station. Column and breaker foundations are also in deteriorated condition and need to be repaired with several potentially needing full replacements.

Figure II

Steel Structures at Lockport are Deteriorated

There are two new 115 kV SF6 breakers while the remaining forty-year old 115 kV oil filled BZ0 breakers show exterior rust and oil stains. Three of the 115 kV oil breakers have continued hydraulic mechanism leaks common to the BZO style breakers. Due to their age, failures of hydraulic system components have been increasing. Each of the oil BZO breakers has aged bushing potential devices which have been another source of failure.

[127] Further details are provided in "Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878" October 1, 2009, Page III-74.

Transformer #60 is a 115/12kV 7.5 MVA transformer manufactured in 1941 which feeds Lockport's station service and Race Street Line 751 which is tied to the Race Street seasonal hydraulic unit. An alternate station service should be provided in case TR #60 or station service fails.

The control room building is also in very poor condition and requires paint and floor repairs. Existing peeling paint is likely lead contaminated. It is an oversized building with continued maintenance costs regarding the original roof and the intricate brickwork. Much of the old 25 cycle control circuitry is still connected to the DC battery and is a potential source of battery ground problems. Rodents are a frequent problem and signs of control wire damage are evident.

Given the number of transmission lines at the Lockport station and the deteriorated conditions of the structures and controls that support them, a station upgrade is proposed to prevent future outages caused by equipment failures.

Lighthouse Hill is a significant switching station for The Company's northern NY region. It has two 115kV buses and seven transmission lines connecting to the station allowing power to flow from the Oswego generating complex to the Watertown area in the north and Clay station in Syracuse. In addition, the station provides a direct source of off-site power and black start capability to Fitzpatrick Nuclear Station[128].

The condition of the station is fair to poor, depending on the specific pieces of equipment being considered. The disconnect switches are in a very poor and hazardous condition, with insulators constantly breaking. Repairs appear to work only temporarily due to the design configuration. Most of the oil circuit breakers (OCBs) are in fair condition, but several are obsolete and would pose a challenge to significant repair.

It should also be noted that the seven OCBs are located 200 ft from the Salmon River located about 70 ft below the grade elevation. The station is located a mile up stream of the NY State wildlife fish hatchery. Although the risk is low, any significant oil spill in the station would have a detrimental environmental impact. There is also the risk of a flooding event at the station given its elevation and proximity to the river.

Another significant issue at the station is that the land is owned by Brookfield Power and operated as a shared facility under a contractual agreement. The hydro station was previously owned by Niagara Mohawk. Not having direct access to Brookfield's control room at Lighthouse Hill is not an ideal situation for The Company as it limits the control we have over the housing conditions for the battery and relay systems. The Company has controls on the first floor of the control house which is immediately adjacent and downstream of Brookfield's hydroelectric dam. A release from the dam would likely flood the control room area. See Figure III illustrating the proximity of the control house to the Salmon River.

[128] Further details are provided in "Report on the Condition of Physical Elements of Transmission and Distribution Systems, Case 06-M-0878" October 1, 2009, Page III-76.

Figure III

Brookfield's Control House at the Lighthouse Hill Site

A new substation needs to be built and relocated to a point on the opposite side of the adjacent road in the clearing near the transmission right-of-way. If not, risks of oil contamination to the Salmon River and station flooding will increase as the OCB’s continue to age.

ALTERNATIVES CONSIDERED:

Speaking collectively for the three stations, two other options to the recommended station rebuilds exist.

Option 1 – Replace components after failure. While there are adequate spares in the system to replace breaker and transformer failures that may occur at these three substations, given the consequences and costs associated with damage/ failure this approach is not recommended. Furthermore, this does nothing to resolve less than ideal station configurations or locations which currently exist.

Option 2 – Deferral. This option is not acceptable given the current asset condition of the three stations. Reliability, already at low levels, will continue to degrade as assets in poor condition continue to deteriorate.

CUSTOMER BENEFITS of PROGRAM:

The planned replacement of these three stations reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

Implementing this program also addresses the need for reliable fault interruption capability for the safety of Company employees and its equipment. In addition, planned replacements are less costly and more efficient than unplanned replacements (failure) and offer the lowest lifetime cost approach for customers.

METRICS TO TRACK BENEFIT(s):

The success of these substation upgrade projects will be shown by an increase in the reliability of the upstate New York transmission system as seen by our customers.

The circuit breaker replacement strategy offers The Company the opportunity to improve the reliability performance of the transmission network. Reliability improvements will be measured by the following indices;

- SAIFI: System Average Interruption Frequency Index
- SAIDI: System average Interruption Duration Index
- CAIDI: Customer Average Interruption Duration Index

COSTS AND AVOIDED COSTS:

In instances of station rebuilds, as those proposed above for Rotterdam, Lockport and Lighthouse Hill, assets are generally replaced on a one-for-one basis, often resulting in the same number of assets in the new station as were in the old. Exceptions of course happen when reconfigurations are made from a single breaker to a breaker-and-a-half scheme for example, which increases the number of assets. Typical station rebuilds due to asset condition will not result in a decreased spending in preventative maintenance. However, we would expect a reduction in trouble maintenance expenses once normal ‘teething problems’ associated with new equipment are corrected.

These new assets will still need all the preventative maintenance of the ones they have replaced. Visual and operational inspections, mechanism tests, diagnostic tests, and dissolved gas analyses for transformers would all still need to be performed.

Furthermore, the circuit breaker and transformer replacement programs also discussed in this filing will offer potential areas for cost savings based on the number and location of strategic spares they create. For example, it would be financially beneficial if the entire population of breakers could be supported by a single, centrally held spare. However, all of these potential OPEX benefits for these three station rebuilds have yet to be fully explored and it would not be prudent to forecast cost savings at this point.

EXHIBIT 21

PROGRAM NAME:

U-Series Relay Replacement Strategy

PROGRAM DESCRIPTION:

A continuing replacement program for the U Series relays and related equipment will reduce the possibility of long term unavailability of one protection system on those transmission lines protected by this equipment. U series relays provide one of two protection systems on a number of key 345kV, 230kV, and 115kV bulk power transmission lines. NPPC Criteria stipulates that Bulk Power transmission lines have two systems of protection. An extended outage of one system could have an impact on the reliability of the interconnected power system. Replacement will also eliminate incremental maintenance time and costs associated with these relays, allowing relay maintenance personnel to focus on other critical protection Issues.

DRIVER(s):

The Westinghouse U series line of relays was introduced in the early to mid 1970's. Production and support for these relays ceased in the mid 1980's. Westinghouse U series relays are at or near the end of their useful life and installed on a number of important 345kV lines in New York.

Replacement parts and support for the Westinghouse U Series relays are no longer available, making continued maintenance of these devices very difficult. Spare parts harvested from previously failed units have been depleted. The option to obtain spare parts from outside sources is essentially nonexistent.

Westinghouse U Series relays have experienced numerous problems over the last several years. Specific test data obtained from the New York Capital district, dating back to 1995, show U Series relays have failed various maintenance tests or settings have drifted enough to exceed specified tolerances.

An un-repairable U Series relay could be out-of-service for an extended period of time before a replacement relay can be installed. This situation would leave the transmission line with a single system of protection for a prolonged period of time. This could have a significant impact on the reliability of the interconnected power system as the circuit would either have to be taken out of service or the power system would have to be run with a constrain to minimize the impact of a single protection failure out side of the local area.

Replacement of the U series relays will yield a more reliable and responsive protection and control system. The microprocessor based replacement relays not only are state of the art, but also offer considerably more capabilities. The new relays consolidate many relay functions into a single package, reducing the need for multiple relays to protect a single line. The relays also have the capability to record information at the time of a power system event, enabling enhanced post event analysis that can lead to improved protection system performance.

OTHER ALTERNATIVES CONSIDERED:

A choice to not replace these relays exposes the company to the risk that a failed relay system may be out-of-service for an extended period of time. Many U Series relays protect transmission lines where the second protection scheme is also an older model relay that may be targeted for asset replacement due to obsolescence or poor product support.

A propensity for settings to drift exposes lines protected by U Series relays to false trips, or failure to trip when called upon to do so. A choice not to replace these relays will result in increased maintenance costs as U Series relays continue to age. It will also result in failed relays being replaced on an unplanned basis, increasing overall expenses. Failure of these relays will also have an impact on the reliability of the interconnected power system.

CUSTOMER BENEFIT(s) OF PROGRAM:

Replacement of U Series relays with modern microprocessor based relays will enhance protection and the capability for capturing critical information during system faults and abnormalities. U Series relays do not have data capture capability.

Benefits obtained from replacing Westinghouse U Series relays include:

1. Improved dependability of the protection schemes will significantly reduce the risk of affecting the reliability of the Bulk Power System.

2. Elimination of a possible source of false trips or failure to trip.

3. As U Series relays are replaced they will provide spare parts for remaining relays thus extending the life somewhat until it can be scheduled for replacement with a new microprocessor based relay.

4. Elimination of incremental maintenance and replacement costs associated with these relays. Replacement relays will be microprocessor based devices capable of self diagnostics.

5. Ability to obtain information not currently available. Replacement relays will be capable of recording and providing fault and abnormal operation data.

METRICS TO TRACK BENEFIT(s):

Metrics measuring the replacement progress are already in place. The metrics track the U Series targeted for replacement based on sanction papers approved through our internal governance process.

COSTS AND AVOIDED COSTS:

The elimination of the Westinghouse U series relays will result in lower operational expense due to the propensity for the U series relays to fail. The microprocessor based replacement relays afford a longer time between maintenance intervals and are also more reliable with a greater Mean Time Between Failures (MBTF).

It should be noted that the expected life of microprocessor based relays is shorter than the life of those from the electro-mechanical era. However, with no moving parts, the microprocessor based relays should not stray from their original settings as is the case with the U series relays. Finally, the replacement relays will have spare parts availability for some time to come, which is not the case today with the U series.

The OPEX savings from the U Series Relay replacement project is primarily due to the reduced periodic maintenance cycle required for the replacement microprocessor based relay versus the electro-mechanical U series relays. The OPEX savings are somewhat offset by the increased labor required to initiate the microprocessor based relay due to its complexity and plethora of settings.

The relay replacement program offers The Company the opportunity for both preventative and troubleshooting maintenance savings in the long term. Driving these savings would be the increase of the preventative maintenance cycle of six years for microprocessor relays compared to the four year cycle for electro-mechanical relays. Also, microprocessor based relays offer other advantages of self diagnostic testing, more secured settings that never require recalibration and are less prone to fail.

<u>Decreased Planned Preventive Maintenance</u>

The replacement of 14 U series relays in NY will result in overall lower maintenance cost. This cost has been estimated as shown below:

<u>Decreased O&M</u>

Periodic Test for electromechanical U series:

1 Technician/8 Hours Every 4 years	$2,800/yr

Periodic test for microprocessor:

1 Technician/8 Hours Every 6 years	$1,900/yr
Net Decreased O&M savings @ $100/hr	$ 900/yr

The U series relays are scheduled to be replaced over the next three years, therefore the full savings will not be realized until the end of the replacement cycle.

Based on an estimated decrease in planned preventive maintenance, savings of $900/year should be realized.

EXHIBIT 22

PROGRAM NAME:

Overhead Line Refurbishment Program

PROGRAM DESCRIPTION:

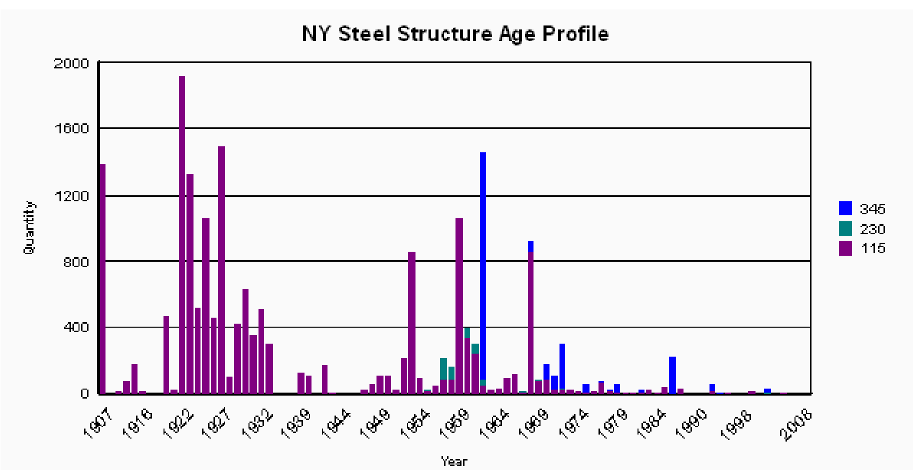
Rebuilding Of Low Reliability Overhead Line Transmission Assets.

DRIVER(s):

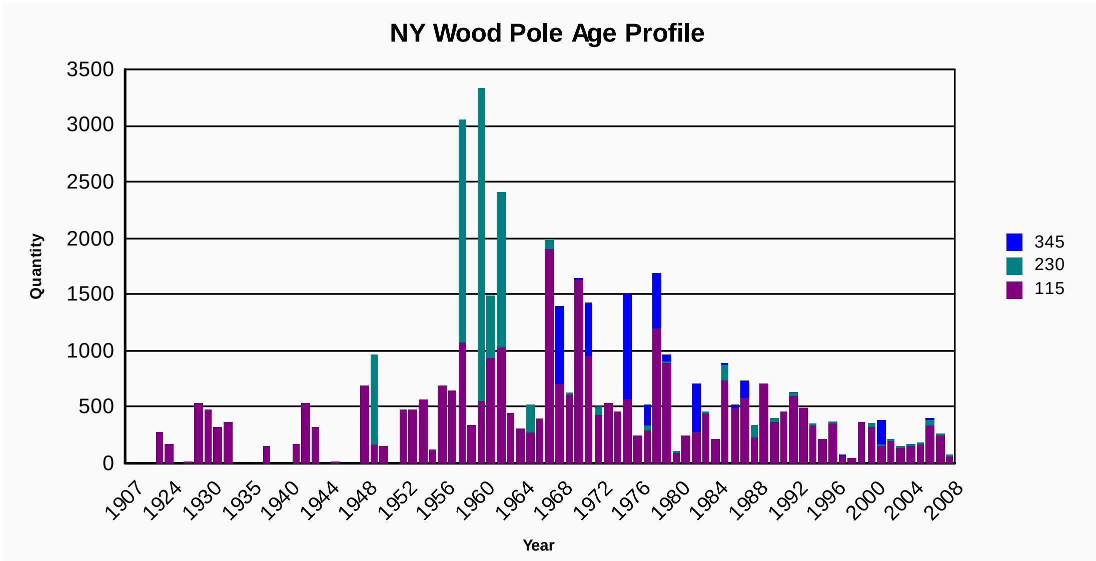
The basic level of this program assures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built. This will be accomplished through the replacement of deteriorating structures and line components that no longer structurally or electrical adhere to the governing National Electric Safety Code. This follows standard industry practice and the Public Service Commission Order (per Case 04-M-0159 effective January 5, 2005) to adhere to the NESC. This approach would be done on a line by line basis and follow a more in-depth engineering evaluation than

the normal five year foot patrol inspections. Lines will be selected based upon their reliability statistics as published in the Transmission Network Performance Report and any circuits that appear in the SGS Statistical Services list of worst 100 circuits. The strategy currently places an emphasis on the worst performing load circuits in New York.

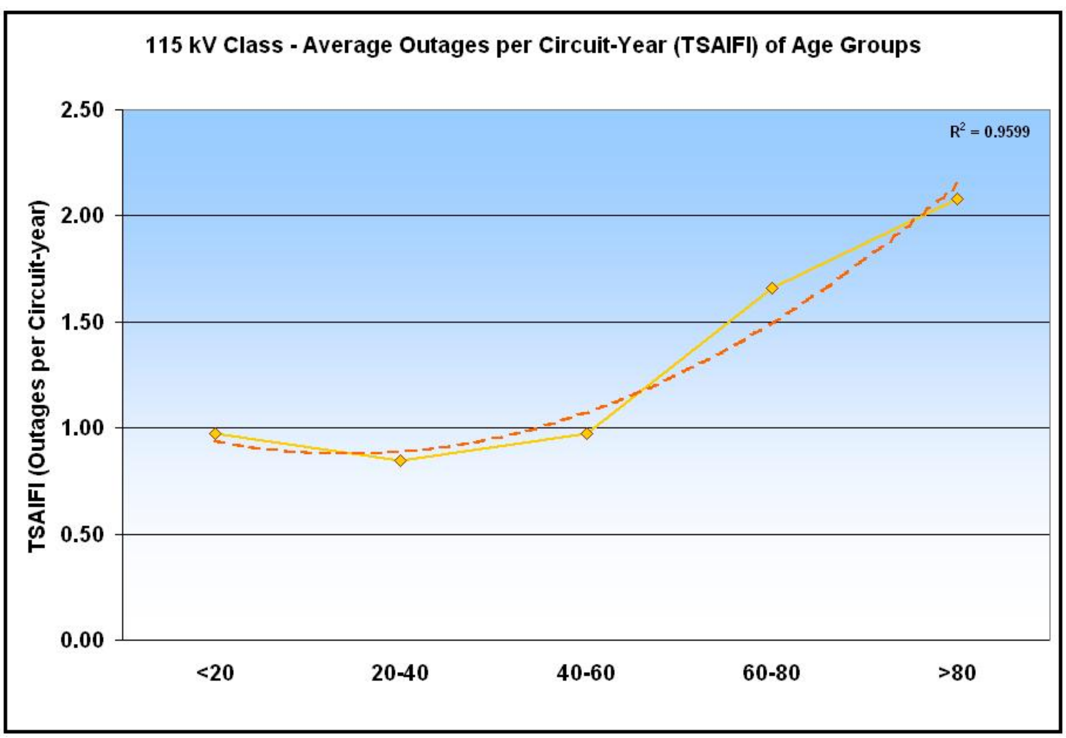
Secondly, the age distribution figures for overhead line assets show an aging population of transmission assets in Upstate New York. A significant portion of the steel structure assets are within the anticipated replacement timeframe of 70 – 110 years (i.e. installed between 1899 and 1939). See the addendum on Asset Modeling at the end of this justification document. The 115 kV population of steel structures is older than the 230 kV and 345 kV one.



For wood poles, a large portion of the assets are also within the anticipated replacement timeframe of 24 to 100 years (installed between 1909 and 1985). In this case, the 115 kV and 230 kV wood pole populations are older that 345 kV wood poles.



A recent evaluation of the 115 kV transmission assets demonstrated a strong correlation between age and decreasing reliability. The following chart clearly shows that as 115kV overhead lines age, the number of outages increases. It is also important to note that even relatively new circuits will still experience outages.



Further, this program is bundled with other overhead line strategies (i.e., conductor clearances and wood pole management) for efficiency reasons, scope, geographic location, outage constraints, licensing and planning. This bundle will impact the sequence and priority for some transmission lines. In addition, consistent with efficiency reasons, normally both circuits on a double circuit line are refurbished at the same time.

OTHER ALTERNATIVES CONSIDERED:

Option 1: Do Nothing Until Failure Occurs.

Reasons for eliminating this option: (A) This option ignores safety to the public. (B) Option 1 ignores reliability of service to the customer. (C) This option lacks long-term sustainability. (D) Deteriorating structures and line components would not continue to adhere to the governing National Electric Safety Code, thereby causing The Company to not conform to Public Service Commission Order (per Case 04-M-0159), as well as not adhering to the NESC.

Option 2: Replace only deteriorated assets near critical crossings.

Reason for rejection: (A) This option improves (but does not eliminate) safety to the public concerns. (B) Reliability of service to the customer would remain at risk. (C) It lacks long-term sustainability. (D) Deteriorating structures and line components would fail to continue to adhere to the governing National Electric Safety Code. Thus, The Company would fail to conform to Public Service Commission Order (per Case 04-M-0159), thereby not adhering to the NESC.

Option 3 (Recommended): Replacement based significantly upon actual field condition evaluations. The initial overhead line rebuilding effort will target the least reliable transmission lines based on their five year average performance. Lines will be selected based on their reliability statistics as published in the Transmission Network Performance Report and any circuits that appear in the SGS Statistical Services list of worst 100 circuits. The final prioritization would factor in actual asset condition, line criticality, outage constraints, and line reliability data. Deteriorating structures and line components that no longer structurally or electrically adhere to the governing National Electric Safety Code would be refurbished or replaced. Thus, The Company conforms to Public Service Commission Order per Case 04-M-0159, adhering to the NESC. In addition, for efficiency, the refurbishment would be "enhanced" for overall reliability centered improvements and with the intention of bringing the line up to more modern design practices.

Option 4: Replace based on an overhead line replacement and refurbishment model using technical asset lives for overhead line components, without regard to asset condition or reliability.

Reason for rejection: Environmental conditions and past maintenance practice will impact the lifetime of various overhead line assets. Other factors, such as the install design and construction specifications and vandalism (i.e., insulators for target practice) can also impact asset lifetimes. This option (A) would not efficiently improve reliability, (B) not optimize public safety, and (C) would cause some assets to be replaced prematurely, before nearing end-of-life.

Option 5: Follow option 3 but only refurbish in order to assure the line continues to meet the governing NESC. The initial overhead line rebuilding effort will target the least reliable transmission lines based on their five year average performance. Lines will be selected based on their reliability statistics as published in the Transmission Network Performance Report and any circuits that appear in the SGS Statistical Services list of worst 100 circuits. The final prioritization would factor in actual asset condition, line criticality, outage constraints, and line reliability data. Only deteriorating structures and line components that no longer structurally or electrically adhere to the governing National Electric Safety Code would be refurbished or replaced. Thus, The Company conforms to Public Service Commission Order (per Case 04-M-0159), adhering to the NESC.

Reason for rejection: Option 5 helps to assure that reliability declines are limited. However, it would do relatively little to help to improve overall long-term transmission reliability and potential future sustainability. In addition, the “replace in kind” scopes would be such that the Article VII process, aimed at identifying better alternatives and options, would not be necessary.

CUSTOMER BENEFIT(s) OF PROGRAM:

Maintenance of appropriate public safety levels by assuring that the basic level of this program ensures that The Company transmission lines meet the governing National Electric Safety Code (NESC) under which they were built by replacing Deteriorating structures and line components that no longer structurally or electrically adhere to the governing National Electric Safety Code. This follows standard industry practice and the Public Service Commission Order (per Case 04-M-0159 effective January 5, 2005) to adhere to the NESC.

This strategy provides a long-term approach to addressing Level 3 substandard spans in New York as described in the conductor clearance strategy justification document.

The basic level approach is the lower cost option compared to a replace-on-fail approach. Replace on fail introduces additional direct costs such as overtime work plus indirect ‘lost opportunity’ costs such as the ability to bundle work and maximize efficiency.

The “enhanced” level of this program is aimed at improvements in the overall reliability of the specific lines refurbished and improvements in the Transmission Performance Scores and with the intention of bringing the line up to more modern design practices. This approach is consistent with good asset management practices (i.e., PAS 55).

The enhanced level might result in a corresponding reduction in the overall numbers of “reject” and “priority reject” wood structures as described in the wood pole management justification document.

In addition to reducing safety risk and improved line reliability, this "enhancement" part of the program could help to prevent local and widespread system disturbances, mitigate reputational risks, reduce the likelihood and impact of unplanned failure, prevent additional costs associated with emergency repairs, sustainability, and improve overall transmission security.

METRICS TO TRACK BENEFIT(s):

Reliability indices such as the transmission performance score (TPS), TSAIDI, and TCAIDI should improve during the decade following completion of the line refurbishments.

COSTS AND AVOIDED COSTS:

The OPEX savings from the initiation of the Overhead Line Refurbishment and Replacement Policy is anticipated to come from:

- Reduction in Trouble Maintenance
- Decreased Planned Preventive Maintenance

At this point the anticipated savings are **conceptual** in nature. This analysis looks at the typical savings over the next 10 years.

Reduction in Trouble Maintenance

Currently, momentary disturbances on The Company's New York system are selectively patrolled; therefore, limited or no OPEX saving is to be gained as a result of a reduction in disturbance patrols of momentary disturbances caused deteriorated conditions on lines.

Sustained disturbances require OPEX expenditure to patrol and restore the system. Each disturbance assumes an average of 3 man-hours to find and 6 man-hours to fix. If $100 per hour is assumed, this yields a labor savings of $900 per event. In addition, $100 worth of materials is assumed for a typical average total of $1,000 per event.

This analysis assumes the 18 worst circuits are refurbished over the next 10 years. (Refurbishments are beginning in FY2009/10 with the northern portion of the Gardenville-Homer Hill 151-152 in the Fall of 2009.)

For the 40 worst circuits, there have been 342 sustained outages over a five year period[129], or 63.4 per year. The average amount of sustained outages is typically 30 per year for the 18 circuit. In 10 years, if this is reduced linearly to 6.3 per year[130], trouble maintenance would be reduced. Over 10 years, assume an average sustained outage rate of 18.2 per year, or a savings of $11,850 per year.

[129] Assumes a TSAIFI-S (total number of sustained circuit outages per year) of 1.66, based upon the The Company US FY2009 Annual Network Performance Report.
[130] Assumes an average TSAIFI-S of 0.35 per circuit.

		TAIFI-S	OpEx Savings
1	FY2009/10	30.0	$0
2	FY2010/11	27.4	2,633
3	FY2011/12	24.7	5,267
4	FY2012/13	22.1	7,900
5	FY2013/14	19.5	10,533
6	FY2014/15	16.8	13,167
7	FY2015/16	14.2	15,800
8	FY2016/17	11.6	18,433
9	FY2017/18	8.9	21,067
10	FY2018/19	6.3	23,700

While a reduction in trouble maintenance is anticipated as a result of the overhead line refurbishments by the strategy – the system continues to age and it will take 20-25 years to begin to see a significant change in the average age of overhead lines if this strategy is pursued. Sustained outages on these other circuits could increase wiping out these projected savings on the limited circuits replaced.

Decreased Planned Preventive Maintenance

An initial savings on painting, footer inspection & repairs, and ground-line treatment is expected. Consistent with paragraph 19 in Strategy SG052, approved on 24 Feb 2006, the new steel structures will not be painted or the footers repaired during the first painting and footer inspection & repair cycle after installation. However, this will most likely occur in the following 20-year cycle. Ground-line inspections and treatments generally do not occur for the first 20 years.

	Per Structure	Current Cycle (years)	Annual Ave. Per Structure
Painting	$2,600	15	$175
Footer	$1,800	20	$90
Ground	$250	10	$25

Based upon the projections of the OHL Model[131], for the next ten years, the following structures will need replacement along with the savings:

[131] Wood Poles from Figure 10 in the SG080 Technical Report are cut by 50% assuming this is split with replacement by the Wood Pole Management Program.

	Fiscal Year	Wood Pole Structures	Steel Poles & Towers	Annual Painting Savings	Annual Footer Inspections & Repair	Ground-line Inspections and Treatments	Additive Total OPEX	Groundline & Footer Only
1	FY2009/10	5	20	3,467	1,800	125	5,392	1,925
2	FY2010/11	5	120	20,800	10,800	125	37,117	12,850
3	FY2011/12	10	360	62,400	32,400	250	132,167	45,500
4	FY2012/13	25	550	95,333	49,500	625	277,625	95,625
5	FY2013/14	50	450	78,000	40,500	1,250	397,375	137,375
6	FY2014/15	85	310	53,733	27,900	2,125	481,133	167,400
7	FY2015/16	125	340	58,933	30,600	3,125	573,792	201,125
8	FY2016/17	150	470	81,467	42,300	3,750	701,308	247,175
9	FY2017/18	180	650	112,667	58,500	4,500	876,975	310,175
10	FY2018/19	200	800	138,667	72,000	5,000	1,092,642	387,175

The Company reinstated the painting program after the acquisition of Niagara Mohawk. This OPEX program had been discontinued by Niagara Mohawk for a number of years prior to the acquisition. Therefore, this is not included as an OPEX savings to the base program.

The footer inspection & repair as well as the ground-line inspection and treatment programs did exist at the time of the acquisition and so these savings are included in the chart below.

The complete OPEX savings is expected to be realized after 10 years when all of the 18 worst circuits have been refurbished. Based on this schedule, the following annual OPEX savings are anticipated over the next 4 years:

	FY2010/11	FY2011/12	FY2012/13	FY2013/14	FY2014/15
Trouble Calls	2,600	5,300	7,900	10,500	13,000
Maintenance	$12,900	$45,500	$95,500	$137,400	$167,500
Total (Approx.)	**$15,500**	**$50,000**	**$105,000**	**$150,000**	**$180,000**

EXHIBIT 23

PROGRAM NAME:

Transformer Replacement Strategy

PROGRAM DESCRIPTION:

The scope of this major program includes replacement of the 39 highest priority transformers based on their condition and performance. The scope includes the transformers (including radiators, fans and pumps), associated civil works, surge arresters, and bus connections. A substation condition assessment during conceptual engineering and prior to sanction approval will determine the final scope of the work. Discussions with Transmission and Distribution Planning will ascertain whether demand side reduction can be achieved resulting in like-for-like transformer replacement or whether a transformer with additional load carrying capacity is required to meet the forecasted load growth.

DRIVER(s):

Reliability - Transformers play a key role in providing customers with a reliable service. The unforeseeable failure of a transformer can lead to customers being off-supply for long periods of time until the load can be re-switched, or in many instances, until a mobile substation can be delivered and installed. The following table lists those transformers that, over the past six-years, either failed unforeseeably or were taken out-of-service based on exceptional dissolved gas analysis results.

Date Manufactured	Substation	Failure Date
1965	Station 212	20-Jan-03
1965	Station 212	20-Jan-03
1959	Dunkirk TB 41	17-Feb-03
1926	Inghams TR #3 - B phase	31-Mar-03
1955	Packard # 2	01-Apr-03
1953	Swann Road 105 TB #1	01-Jun-03
2001	Mobile 3E TR #66	11-Oct-03
1989	Mobile 5E	01-Jan-04
1989	Mobile 6W	01-Jan-04
1989	New Scotland #2	15-Jan-04
1952	Brook Road	01-Mar-04
1968	Station 78 TR #2	12-May-04
1991	Dugan Road TR	22-Sep-04
1966	Mobile 3C	21-Mar-05
1960	Clay #2	14-Apr-05
1940	Mountain TB #2	05-Jul-05
1961	Boyntonville TB1	26-Oct-05
1957	Kennsington Terminal Sta TR #2	12-Jan-06

1963	Maplewood TR #2	12-Apr-06
1988	Malta TR #2	22-Apr-06
1958	Madison	30-Apr-06
1991	Belmont TR #2	05-May-06
1938	Shaleton	14-May-06
1964	Mobile 5W	29-Jun-06
1970	North Troy TR #3	02-Dec-06
1990	New Walden TR #1	23-Dec-06
1964	Saint Johnsville TR #2	29-Mar-07
1966	Oneida TR #3	23-Apr-07
1990	Rotterdam TR #1	28-Jun-07
1967	New Gardenville TB 2	04-Oct-07
1959	Dunkirk TB 31	29-Oct-07
1964	Terminal Station TR #3	05-Nov-07
1981	West Hamlin TR #1	07-Nov-07
1967	Senaca Terminal - 72E Reactor	08-Jan-08
1974	Ogdensburg TR #2	09-Jan-08
1963	McIntyre TR #1	15-Jan-08
1992	Schodack TR #1	25-Jan-08
1968	Brigham Rd TR #1	04-Mar-08
1969	Riverside TR #2	22-Aug-08
1969	Fly Rd TR #1	15-Jun-09
1977	Hudson TR #4	19-Oct-09

Safety - The energy of an internal fault within a transformer creates the possibility that failure may cause a breach of the transformer tank, possibly resulting in:

- explosion and flaming oil being expelled from the transformer tank
- transformer tank parts (particularly bolt heads, etc) being projected at high velocity
- transformer noise enclosure collapse
- porcelain shattering upon failure of transformer bushings

Environment – Not all transformers are currently provided with oil containment facilities. There is a risk to the aquatic environment due to oil leaking from transformers with deteriorated gaskets and bolts that may have vibrated loose. Other less likely environmental impacts of transformer failure are associated with smoke, which despite their rare occurrence, should still be taken into account for transformers located in densely populated areas.

Sustainability – If the replacement rate of the past 10 years is perpetuated, by 2020, there will be more than 150 transformers over the age of 55 (anticipated asset life) including 57 transformers over the age of 80.

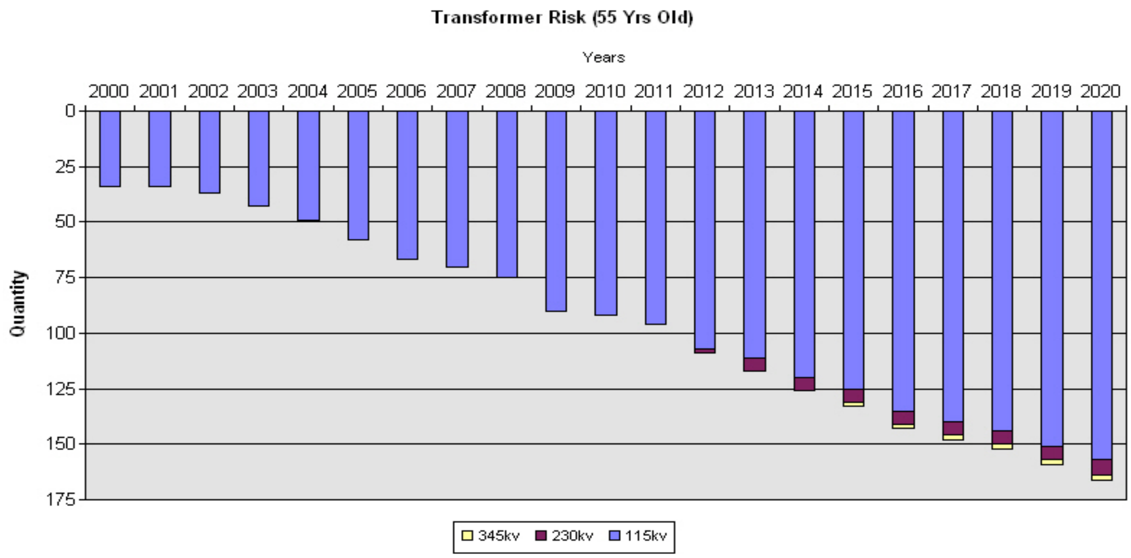


Figure 1 - Transformers in NY over 55 years old

While it is recognized that age is not always a reliable indication of condition, the use of age as a proxy for condition is considered justifiable in the case of power transformers. This is because the degradation mechanism for paper insulation is well understood, and the asset lives are supported by CIGRE and other industry statistics. As the paper ages, it becomes mechanically brittle and susceptible to dielectric failure if mechanically disturbed (as experienced during through-faults). The rate of ageing is mainly dependent upon the temperature and moisture content of the insulation and ageing rates can be increased significantly if the insulating oil is allowed to deteriorate to the point where it becomes acidic. The thermal aging of paper insulation is also a chemical process that liberates water. Any moisture that enters the transformer during its operation and maintenance will also tend to become trapped in the paper insulation. Increased moisture levels may also cause dielectric failures directly or indirectly due to formation of gas bubbles during overload conditions.

OTHER ALTERNATIVES CONSIDERED:

Option – 1: Do Nothing (Replace-on-fail) – this option is not recommended. The adoption of a replace-on-fail approach for power transformers will have significant consequences and risks, thereby downgrading the system's safety and reliability standards. The current unforeseeable failure rate is increasing, and it cannot be sustained with the existing level of strategic spares. If failure rates were to worsen in line with predictions by asset life models, the system impact and the consequences for customers would be difficult to manage, given the replacement transformers' long lead times.

Option – 2: Replace on age – this option is not recommended. Currently, there are approximately 90 transformers over 55 years old on the Transmission system. This will increase to approximately 150 transformers by 2020, in the absence of a proactive replacement strategy. This large volume represents an elevated level of risk.

As stated above while it is recognized that age is not always a reliable indication of condition, the use of age as a condition proxy for power transformers is justified. This is because the degradation mechanism for paper insulation is well understood. Hence, although age is not a driver for replacement, it does provide a good indication of the likely replacements' volume required in the future.

Option – 3: Replace-on-condition – this is the recommended option. In the short-term, the Company has produced a prioritized list of 39 transformer replacement candidates (see Appendix 1). These are known to be in poor condition based on the results of dissolved gas analysis, electrical testing, or continuous monitoring. These candidates will be replaced over the next six years.

Option – 4: Purchase Extra System Spares/Mobile Substations – this is not recommended. Although this option may help reduce the time to replace a failed transformer with a system spare/mobile substation, it would not improve the overall reliability of the upstate New York Transmission system. A damage/failure replacement strategy is inherently more costly to the customer than a long term planned asset health replacement strategy. In addition, the damage/failure strategy does not address any of the safety, environmental, and sustainability issues.

Option – 5: Rebuild Transformers – this is not recommended. For large power transformers, the cost / benefit ratio of buying a new transformer compared to a rebuilt transformer makes this option unrealistic. The two way transportation costs alone make this option expensive. Other issues to consider are the relatively short additional life that can be obtained through refurbishment and the uncertainty over whether the rebuilt transformer will pass factory acceptance tests.

CUSTOMER BENEFIT(s) OF PROGRAM

This high priority replacement strategy would minimize the reactive (damage/failure) impact of transformer failures for our customers in upstate New York, while increasing the overall dependability and reliability of the system. This is a pro-active strategy for improving the overall reliability of the upstate New York transmission system.

This program does not intend to address all of the reliability risks associated with the New York system's overall population of power transformers. It only targets transformers with known manufacturer's design issues, transformers with damage experience through faults, and transformers with unusual Dissolved Gas Analysis signatures.

The average size rating of the 39 transformers in Appendix 1 is 17MVA, which equates to approximately 17,000 residential customers that would be impacted by a transformer failure. If a failure were to occur, the time needed to install a mobile substation and/or install a system spare could result in the interruption of millions of customer minutes. As a result of unforeseeable failure, lost opportunity costs could be substantial (e.g.: loss of production, loss of retail sales, etc.). Regardless of the sector, the economy virtually shuts down when power goes out unexpectedly. Some costs may be recoverable once the outage ends; however, the vast majority of the value is simply lost. The state of the economy (and the economy of the State) and the supply of electric power are inextricable linked".[132] This program aims to minimize these losses.

METRICS TO TRACK BENEFIT(s):

The Company US Transmission has a population of 508 transformers in upstate New York, with an anticipated asset life of between 50 and 80 years. An asset replacement rate of 6 to 9 transformers per year would be anticipated over the next ten to twenty years to maintain the upstate New York transformer fleets system reliability.

The success of this strategy will be measured by a reduction in the number of high priority transformers on the upstate New York Transmission System. In addition, the success of this program will be measured by demonstrating no increase in the number of unforeseeable transformer failures each year. This will translate into SAIFI, CAIDI and LCM improvements.

COSTS AND AVOIDED COSTS

There may be a small OPEX savings associated with the removal of problematic assets from the substations, but the amount is not significant. The installation of low (or no) maintenance tap-changers will also produce additional OPEX savings.

Depending on metal prices at the time of retirement, there maybe a credit associated with the salvage of each transformer and their associated equipment.

[132] Profiting from Transmission Investment - A holistic, new approach to cost/benefit analysis. Public Utilities fortnightly, October 2004.

Appendix 1

	Transformer	Replacement Year	Reason
1	Batavia TB20		DGA
2	Harper TB30 LTC		O&M
3	Harper TB40 LTC		O&M
4	Kensington Terminal TB4 LTC		O&M
5	Tilden Station 73 1 TRF		O&M
6	Tilden Station 73 2 TRF		O&M
7	Seneca Terminal TB2		O&M
8	Seneca Terminal TB3		DGA & O&M
9	Seneca Terminal TB4		DGA &O&M
10	Seneca Terminal TB5		O&M
11	Bristol Station TB1 LTC		DGA
12	Clay Station TB1 AUTO		DGA &O&M
13	Dewitt TB2 AUTO		O&M
14	Edic TB4 AUTO		O&M
15	Nicholville TB1		DGA
16	Oneida TB4 LTC		O&M
17	Solvay TB1		O&M
18	Solvay TB2 replace 1st		DGA & O&M
19	Solvay TB3		O&M
20	Solvay TB4		O&M
21	Teall Avenue TB7 LTC		O&M
22	Teall Avenue TB1		O&M
23	Teall Avenue TB2 replace 1st		DGA & O&M
24	Teall Avenue TB3		O&M
25	Teall Avenue TB4		O&M
26	Terminal Station TB2 LTC		DGA & O&M
27	Valley TB3		DGA & O&M
28	Altamont TB1 A		DGA & O&M
29	Altamont TB1 B		DGA & O&M
30	Altamont TB1 C		DGA & O&M
31	Hoosick TB1		DGA & O&M
32	Leeds TB3 SVC B		O&M
33	Leeds TB3 SVC C		O&M
34	Mohican TB1		DGA & O&M
35	Oswego TB111 A,B,C		DGA & O&M
36	Porter TB1 AUTO		O&M
37	Porter TB2 AUTO		O&M
38	Woodlawn 1TRF LTC		O&M
39	Woodlawn #2 TB A,B,C into 1- 3 phase		DGA & O&M

EXHIBIT 24

PROGRAM NAME:

Circuit Breaker Replacement Strategy

PROGRAM DESCRIPTION:

The circuit breaker replacement strategy currently under development will address problematic circuit breakers in New York.

The scope of this strategy is to purchase and install approximately 130 SF_6 (gas) circuit breakers over the next ten years (replacing high priority oil circuit breakers). Additionally, where cost effective and where their condition warrants, the opportunity will be taken to replace disconnects, control cables and other equipment associated with these circuit breakers.

Of the 130 oil circuit breakers, 37 are being replaced due to inadequate short circuit interrupting capabilities. The remaining ones are being replaced based on known condition issues.

This program includes 4 projects with forecasted spending levels greater than $2M.

DRIVER(s):

There are three different drivers for this strategy – reliability, safety and environmental with reliability being the primary driver.

The Company has an operational circuit breaker population totaling 650 units of various manufacturers, voltage ratings and technologies. 43% of the circuit breaker population is of the newer technology SF_6 (gas) type and generally in good serviceable condition (requiring little maintenance). 57% of the circuit breaker population is of the bulk oil type (OCBs). These breakers were manufactured and installed over a forty-three year period from 1951 through 1994.

Due to the key function carried out by circuit breakers, particularly for fault clearance, they cannot be allowed to become unacceptably unreliable. 11% of sustained outages on the bulk system and 12% of sustained outages on the non-bulk system are caused by substation equipment including circuit breakers.

The second driver is safety related. With historical data depicting the earliest onset of breaker failures occurring in the forty year range, the possibility of these breakers failing during fault interruption duty is increasing. The Company has already experienced failures of bulk oil circuit breakers within the transmission system in New York. Equipment failures at these high voltages (115 Kilovolts and above) have the potential to be extremely dangerous, resulting in erratic voltage dissipation and flying debris. In many cases, adjacent equipment is damaged, further increasing the risk of injury.

The final driver is environmental concerns associated with oil filled equipment failures, which are also an area of concern. Typical bulk oil circuit breakers contain 1500+ gallons of oil. Incidents have occurred where the force resulting from the circuit breaker failure was powerful enough to rupture the tank, causing extensive and costly environmental clean up.

OTHER ALTERNATIVES CONSIDERED:

Option1 – Do Nothing

This option would have no initial cost. However, there will be indirect costs associated with increased maintenance levels. This would involve no proactive replacement of equipment, except when failure occurs.

This option is unacceptable because:

- Leaving degraded circuit breakers in service puts the company and customers at risk of long-term interruptions of the transmission system.
-
- Violent failures of this equipment have the potential to cause extensive damage to other equipment as well as serious injuries to our employees.
-
- All circuit breakers should be replaced before their latest onset of significant unreliability.

Option 2 - Refurbishment

This option gives consideration to major refurbishment as opposed to replacement.

This would involve the disassembly of the majority of the circuit breaker components. These components would need to be refurbished back to original design tolerances. Also, replacements of any worn out or degraded parts would need to be acquired. Due to a lack of Manufacturer support and the inability to locate replacement parts, this option is likely to be more costly in the long-term.

Refurbishment is a one-off activity and cannot be repeated indefinitely. Refurbishment may have limited application where it is not possible to replace circuit breakers due to outage or other constraints.

Option 3 – postpone replacement for 5 years

This option will defer replacements for the bulk-oil circuit breaker population for 5 years.

There are approximately 90 circuit breakers at or beyond their anticipated asset life. There is evidence of deterioration through known failure mechanisms and in some cases, circuit breakers are being kept in-service using salvaged second- hand parts from retired equipment. This approach is not considered sustainable.

This option is not acceptable given the current asset conditions. Reliability, already at low levels, will continue to degrade as assets in poor condition further deteriorate.

Option 4 – planned replacement based on family types or sites (recommended)

This recommended option involves proactively replacing 90 bulk oil circuit breakers in New York over the next ten years.

This will eliminate the risks of interruptions, outages, safety and environmental concerns associated with equipment failures and replace assets on the system that are clearly at their end of life.

CUSTOMER BENEFIT(s) OF PROGRAM:

The planned replacement of these circuit breakers reduces the likelihood of a in-service failure which can lead to long-term interruptions of the transmission system as well as significant customer outages.

Implementing this strategy also addresses the need for reliable fault interruption capability for the safety of our employees and equipment. In addition, planned replacements are less costly and more efficient than unplanned replacements (due to failures). Planned replacement offers the lowest lifetime cost approach for customers.

METRICS TO TRACK BENEFIT(s):

The circuit breaker replacement strategy offers The Company the opportunity to improve the reliability performance of the transmission network. Reliability improvements will be measured by the following indices:

SAIFI: System Average Interruption Frequency Index

SAIDI: System average Interruption Duration Index

CAIDI: Customer Average Interruption Duration Index

Assuming that replacing all of the circuit breakers would lead to a 10% reduction in sustained outages caused by substation equipment failures and given the fact that substation equipment failures cause 12% of the total system outages, then approximately 1.2% of total system outages could be avoided through the implementation of this program.

COSTS AND AVOIDED COSTS:

The OPEX savings from the Circuit Breaker replacement project come mainly from two sources:

- Reduction of Unplanned Trouble Maintenance
- Decreased Planned Preventive Maintenance

Reduction in Trouble Maintenance

During the last two years, the average amount spent on unplanned trouble maintenance on bulk oil circuit breakers reached $60,000/year.[133] Since replacement breakers are new and have a much improved design, they rarely incur any unplanned trouble maintenance. Therefore, it can be assumed that the entire cost of $60,000/year will be saved by replacing these breakers with new, modern equipment.

Decreased Planned Preventive Maintenance

Since bulk oil circuit breakers are larger and more maintenance intensive than modern equivalents, planned preventive maintenance takes longer and requires more technicians. In addition, since they are less reliable overall, maintenance intervals are shorter. This results in an annual reduction in the overall planned maintenance costs when bulk oil circuit breakers are replaced. In fact, the overall maintenance costs for a modern breaker are about 1/3 of those for bulk oil circuit breakers:[134]

Oil Circuit Breakers

Diagnostic Test:	4 Technicians/24 Hours Every 72 months	$1,600/yr
Mechanism Test:	2 Technicians/8 Hours Every 24 Months	$1,600/yr
		Total - $3,200/yr

Modern Gas Circuit Breaker

Diagnostic Test:	3 Technicians/16 Hours Every 108 months	$533/yr
Mechanism Test:	2 Technicians/4 Hours Every 24 Months	$400/yr
		Total - $933/yr

[133] Data is based on AIMMS trouble report data.
[134] Data based on The Company maintenance standards and current work practices. Labor rates based on $100/hour

Based on this, $2,267/year can be saved on planned preventive maintenance for each oil circuit breaker which is replaced. The total savings for the 90 breakers replaced under this strategy is roughly $200,000/year.

Based on average historical unplanned trouble maintenance spending of $60,000/year and calculated planned preventive maintenance spending of $200,000/year, a total yearly OPEX savings of $260,000 will be realized when all bulk oil circuit breakers are replaced.

EXHIBIT 25

PROGRAM:

Surge Arrestors

DESCRIPTION:

There are approximately 700 surge arresters at 115kV and above installed on the New York system. Information suggests that up to 79 percent of all surge arresters are the silicon carbide type, with a large volume estimated to be over thirty years old. The Company experiences on average three surge arrester failures each year and the vast majority of the surge arrester failures are of the silicon carbide type.

Currently, the lifetime of a silicon carbide surge arrestor is anticipated by The Company to be approximately 20-25 years. The integrity of silicon carbide arresters beyond this time frame cannot be guaranteed due to concerns over pollution performance, poor mechanical reliability (e.g. poor seals, internal corrosion, etc) and difficulty of monitoring the condition of the series gaps. In an October 1996 issue of the IEEE Transaction on Power Delivery, Dr. M Darveniza recommended that all silicon carbide arresters that have been in service for over 13 years be replaced due to moisture ingress. His tests revealed that degradation was evident in 75% of arresters tested. One manufacturer also reports that moisture ingress is the direct cause of failure in 86% of all cases.

DRIVER(s):

This program is driven by reliability, safety to personnel and the prevention of damage to other equipment during lightning or switching over-voltages.

The failure of a surge arrester can lead to damage to expensive wound equipment such as power transformers during switching or lightning transient over-voltages. This project should be undertaken in order to ensure that expensive equipment is adequately protected, thereby reducing costs to customers in the long-term.

There have been 62 damage / failure work orders created over the past three years for surge arrester failures (17% and 25% of all TxT and DxT work orders respectively).

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Do not replace after failure. Although this is the least cost option, it is not recommended. The potential for damage to wound equipment such as power transformers or potential transformers during a switching or lighting surge will still exist.

Option 2 – Replace after failure. This reactive approach is not recommended because a surge arrester may fail during a switching or lightning transient and damage expensive wound plant. A surge arrester is designed to be a low cost insurance against transient over-voltages and needs to be reliable. Silicon carbide arresters can fail catastrophically, creating a safety hazard and the potential for collateral damage to adjacent plant.

Option 3 – Planned replacement. This option is not recommended due to the large volume of primary equipment outages that would be required to achieve the objective. Typically surge arresters are located on the transformer.

Option 4 – Replace during maintenance. A substation maintenance standard currently exists to replace silicon carbide surge arrestors with modern metal oxide types during scheduled maintenance.

Option 5 – Deferral. Deferral of the program to replace surge arresters may lead to damage of expensive wound equipment during switching or lightning events. A flashover inside a power transformer may lead to irreparable damage, necessitating the replacement of the transformer at a cost in excess of $2 million.

CUSTOMER BENEFIT(s) OF PROGRAM

Option 4 is the least cost alternative but will replace silicon carbide surge arresters over a longer period of time. This approach is the least disruptive while managing the risk to wound plant from switching or lightning over-voltages.

The replacement of a low cost surge arrester to prevent damage to wound primary equipment such as a power transformer is beneficial to customers in the long-term.

METRICS TO TRACK BENEFIT(s):

The success of this project will be measured by the number of silicon carbide arresters replaced each year and improvements in SAIFI and CAIDI performance.

COSTS AND AVOIDED COSTS:

There will be no additional maintenance OPEX costs as a result of this program as replacement surge arresters require no additional planned preventative maintenance beyond that already required.

EXHIBIT 26

PROGRAM NAME:

Transformer Replacement – Packard and New Gardenville

PROGRAM DESCRIPTION:

Packard – Replace Transformer Banks 3 and 4

New Gardenville – Replace Transformer Banks 3 and 4

This strategy will replace all four remaining General Electric 230/115kV 125MVA transformers in the Buffalo area. These four transformers at the New Gardenville and Packard stations are a critical link between the 230kV and 115kV systems in western New York. The two projects are to be executed over a 5 year period, ending in 2014.

DRIVER(s):

These two projects are driven by reliability and the need to replace the worst condition transformers ahead of failure. Replacement will:

- minimize the safety risk to personnel,
- reduce the likelihood of widespread system disruption and local losses of supply
- minimize the likelihood of environmental damage due to oil spillages
- maintain reliability of service for the benefit of customers

The Packard and New Gardenville transformers have a unique and unusual construction that makes field maintenance impossible and it is probable that all four transformers are subject to an un-repairable defect which has already caused failure in another identical unit. Failure of one or more of these units could have serious safety, environmental and network reliability consequences.

The 230/115/13.2kV 125MVA transformers at New Gardenville and Packard were built by General Electric between 1957 and 1958 and are the last of their kind on The Company's network. An identical transformer (Dunkirk TB31) failed in October 2007 and an internal inspection performed on this unit prior to failure showed no problems. A post failure inspection of this unit showed a failure of a tap changer lead near the bottom of the transformer. This lead appeared to be over-insulated, leading to thermal failure. There is a high probability that this condition exists on the Packard and New Gardenville units, but due to the construction of the units, this cannot be confirmed through inspection.

All four of these units generate moderate to high levels of combustible gases, which indicates internal overheating problems and is consistent with transformers that are approaching end of life. In addition Packard TB3 has a similar gassing pattern to the failed Dunkirk TB31.

The Packard and New Gardenville units are Load Tap Changing transformers that utilize a General Electric LR-69 model tap changer. The tap changer and reversing switch for each phase are located within the main tank and are not accessible for visible inspection without a complete disassembly of the unit. Complete disassembly would require mobilization to an appropriate rebuild facility. In addition spare parts for these tap changers are no longer available.

The 13.2kV and 230kV bushings on these transformers are General Electric Type U, which have been acknowledged industry wide as being subject to failure. 230kV replacement bushings are not available for units of this design. In addition, given the tap changer design, there are no replacements for the 115kV bushings. Failure of one of these bushings would mean the retirement of the transformer.

A systematic, planned approach to replacement is the recommended option because it is less expensive in the long-term and minimizes the system and safety risks for customers and personnel.

OTHER ALTERNATIVES CONSIDERED:

Do nothing: The ‘do nothing’ alternative is not considered viable. All four transformers have known condition issues when stressed and they are expected to fail within the next 5 years. Replacement following failure would be more costly. The Packard units are in the worst condition and replacement is recommended before 2012. If any one of these transformers were allowed to fail, then securing the Buffalo area network against the loss of a second transformer would require the Company to dispatch local generation. The expenditure of running this high cost, low utilization plant would be high and the financial burden would be passed on directly to customers, in addition to the higher than planned costs for replacing the transformer in the first instance.

Purchase additional spares: A similar option to ‘do nothing’ is to purchase two spare transformers and locate them on site in anticipation of the failure. This is a possible option, but again more costly in the long-term because it would require double moves for the transformers.

Defer replacement - If the replacement were deferred beyond 2014, given the known issue and gassing levels, it may be necessary to refurbish the transformers. Based on the age and condition of these transformers, refurbishment is unlikely to provide further life extension. It is also likely that refurbishment would cost in excess of $2m per transformer which is more costly than the replacement cost.

During a review of the region, the Company identified an overload on Gardenville TB3 and TB4 during N-1-1 outage conditions. To correct this overload, a second 230 kV bus tie between the The Company and NYSEG stations at Gardenville would be required. This second tie would maintain a connection to the NYSEG 230/115 kV Gardenville transformers during the contingency, reducing the loading on the The Company transformers. The plan to replace TB3 and TB4 at Gardenville with larger units will resolve the contingency loading issue, thus allowing the bus tie project to be canceled. If the transformer replacement did not proceed as planned, then the additional bus tie would be required at a cost of $5.5m.

CUSTOMER BENEFIT(s) OF PROGRAM:

The planned replacement of these transformers reduces the likelihood of an in-service failure which in turn reduces the possibility of severe disruption to the Buffalo area network. The failure of the Dunkirk TB31 and Gardenville TB2 transformers led to major disruption of normal system operations, planned maintenance, and the Company's construction program. Therefore, avoiding this kind of disruption reduces the cost to customers in the long-term. In addition, the unplanned emergency replacement of any one of these transformers would undoubtedly be more expensive.

Planned replacement also minimizes the safety risk to personnel and the public by preventing the catastrophic failure of large oil filled transformers. In some cases the in-service failure of a transformer can lead to the transformer tank rupturing, resulting in fire and large volumes of smoke.

Because of the inherently redundant design of the Transmission system, loss of a single transformer does tend to not have a direct impact on customers. However, the benefit of a planned replacement is that it will reduce the likelihood of system events which can weaken the system. Cascading events typically occur when a sequence of failures successively weakens the Transmission system and make further failures even more likely.

METRICS TO TRACK BENEFIT(s)

The benefits of this program will be measured by improvements in SAIFI and CAIDI metrics.

COSTS AND AVOIDED COSTS:

It is assumed that replacing four transformers with new units will eliminate any trouble maintenance expenses for the foreseeable future. However, no planned maintenance costs savings are anticipated as a consequence of these projects. Planned replacement will avoid the additional costs associated with an emergency replacement as well as the costs of securing the system against the next contingency.

EXHIBIT 27

PROGRAM NAME:

Leeds SVC Refurbishment

PROGRAM DESCRIPTION:

This project will replace five out of six major components that make up the Static Var Compensator (SVC) at the Leeds substation in New York. Work to be performed under this project includes the replacement of all components of the SVC that are unreliable, have limited or no parts availability, or are no longer supported by the manufacturer. The six components of the SVC that will be addressed are:

Protection

This component will be replaced. This is the relay system that provides the protection for the interface between the SVC and the transmission network, as well as protecting individual components of the SVC. The system has very limited support from the manufacturer, and some spare parts are not available at all. The system is approaching the end of its useful life and has become problematic.

Control

This component will be replaced as well. It is a sophisticated control system that operates the fast-acting switching thyristor valves in order to achieve the desired reactive support. This component is approaching the end of its useful life. As such, it is becoming increasingly unreliable and difficult to troubleshoot. Also, spare parts, as well as knowledgeable technicians are becoming harder to obtain. Some parts are not available at all. This component is the heart of the system and its failure could render the SVC completely unavailable.

Trigger Pulse System

This component will also be replaced. This is the interface between the control system and the thyristor valves. No spare parts are available for several major parts of this component. Control capacitors in this system have been in service for double their recommended lifetime and are becoming problematic. The capacitors can cause fires when a failure occurs.

Thyristor Valves

These components will be replaced as well. They are the devices that perform the actual switching function. These valves are no longer manufactured so replacements can only be obtained from used inventory. They are prone to occasional failures. Modern valves have greatly improved performance as compared to the ones currently in use.

Cooling System

The existing cooling system and the control system for this component will be replaced. This component removes the considerable heat that is generated by the operation of the thyristor valves. There have been over 25 maintenance trouble calls associated with the existing cooling system since January 2008. The cooling system tripped off a total of 9 times since June 2008, including 4 outages between June 24, 2009 and August 1, 2009.

The control for this component is no longer manufactured and spare parts have limited availability.

External Primary Devices

This component will not be replaced. These are the actual primary reactors, capacitor banks busses and transformers. Any issues with this component have been resolved and if more arise, spare parts would be readily available. The asset condition for this component is good. These components will be completely compatible with any new systems that are installed.

DRIVER(s):

This project is required to address the decreasing reliability of the SVC and obsolescence issues.

Leeds Static Var Compensator (SVC), installed in 1987, has demonstrated declining reliability in the last six years. In February 2003, ABB the manufacturer of the SVC, sent letters to Niagara Mohawk announcing the discontinuation of guaranteed support for the SVC. As a result, there may be no expert support for a component failure, which could lead to prolonged outages of the SVC. Also, some replacement parts for these components are now completely unavailable. The proposed refurbishment work includes the replacement of all SVC components that are unreliable, have limited or no spare parts availability, or are no longer supported by the manufacturer.

An assessment of reactive power support requirements at Leeds Station was performed in 2005 by an ABB consultant working under the direction of The Company. The study found that loss of the SVC would de-rate the New York Central to East (NYCE) boundary flows by 100 MW. The Company reviewed and reconfirmed the study in 2006. A 100 MW reduction of the NYCE capability has the potential to raise wholesale electricity prices for customers in The Company's Eastern NY service territory. It would do so by increasing the number of hours of the year during which the interface becomes a binding constraint on power flows from lower cost generation located in western and central NY.

Since 2000, there have been over 45 documented problems with the SVC, requiring moderate to major maintenance. These problems have occurred mainly in the protection, control, trigger pulse, and thyristor systems.[135] Many of these incidents have resulted in unexpected outages of the SVC, some for extended periods of time. These problems are likely to increase in frequency and severity going forward, thus resulting in an elevated failure risk. This conclusion is also supported by the manufacturer.

OTHER ALTERNATIVES CONSIDERED

Six alternatives were considered in the development of this project. These Options, as presented in Strategy Paper SG059, were:

Option 1: Replace Nothing and Fix Problems as they Occur – Initial cost $0. Although there would be no cost associated with this option initially, it does nothing to address SVC's increasing reliability problems.. This will increase the likelihood that the Central – East interface will be de-rated by 100MW.

Option 2: Decommission the SVC – Estimated cost: $1.0 million – This has the effect of de-rating the Central – East interface by 100MW.

Option 3: Replace Control System Only – Cost: $2.0 million - Although this option is potentially less expensive, it does not address other critical components that are unreliable and have limited spare parts availability. There are also compatibility issues between modern and obsolete components that could render the SVC more problematic. This option will also increase the likelihood that the NYCE will be de-rated by 100MW.

Option 4: Replace SVC with a 345kV Capacitor Bank – Estimated cost: $3.1 million. The amount of reactive power required to maintain the NYCE is 200MVAR. This option would cause an unacceptably high voltage on the 345kV system around Leeds. The maximum amount that could be installed given these constraints (75MVAR) would still cause the NYCE to be de-rated by 75MW.

Option 5: Replace All Unreliable Components (recommended) – Cost: $8.15 million. Replace all components of the SVC that are becoming unreliable, have limited or no parts available or are not supported by the manufacturer. This option has the best prospect for achieving maximum availability of the SVC going forward.

Option 6: Replace the Entire SVC – Cost $20 million+ (estimate) –This option is significantly more expensive than the preferred option. The increase is mainly due to the replacement of extra equipment that does not need replacing. Since there is no significant gain in doing so, this option was not considered.

Option 5 is the recommended option. It provides for the replacement of all problematic components of the SVC. Meanwhile, it does not call for unnecessary replacement of components which are expected to perform well going forward. This will allow for the continued reliable operation of the Leeds SVC for a minimum of 15 years.

[135] Leeds SVC Station Log

Completion of this project will reduce the likelihood of an unexpected outage on the Leeds SVC, which would lead to a de-rating of the NYCE, which is a potentially undesirable situation. This situation could result in decreased reliability, as well as increased congestion costs that would be borne by our customers.

CUSTOMER BENEFIT(s) OF PROGRAM

As stated above, the Leeds SVC has demonstrated increasing unreliability in the past six years. The poor reliability has been especially acute in the protection, control, thyristors, and trigger pulse systems. All of these components are no longer supported by the manufacturer and spare parts are dwindling. In addition, these systems are complex to a point where technical assistance is often needed to fix problems. Currently, this factory assistance is virtually non-existent. A minor failure could force the SVC out of service for several days to even weeks. A major failure could force it out of service permanently until a complete refurbishment is undertaken. In the absence of planning, this refurbishment could take over a year to engineer, procure and execute.

If the SVC were to experience a long term outage, short term congestion may occur, up until the NYISO models the interface to limit the device that is not operating. More specifically, if the device fails and is out of service in Month “3” of a 6-month TCC auction time period, The Company could experience congestion shortfall for 3 months, depending on LMP prices and TCCs sold in the auction. The NYISO would then revise its future TCC auction models to represent a de-rated interface. No shortfall would be expected in that case.

METRICS TO TRACK BENEFIT(s):

The success of this project will be shown by a decrease in the number of outages of the SVC.

COSTS AND AVOIDED COSTS:

The OPEX savings from the Leeds Static Var Compensator refurbishment comes mainly from the reduction of unplanned trouble maintenance. Planned maintenance costs will remain the same after the refurbishment.

<u>Reduction in Trouble Maintenance</u>

The last study of trouble maintenance included the years 2000 – 2005. This is based on information gathered from the station log and estimated hours to solve each problem. Typical problems are as follows:

Problem	Employee Hours per Incident[136]
• Thyristor Change	16
• Replace Safety Valve	4

[136] Costs are based on an average employee/overhead cost of $100/hour.

• Replace Capacitor	4
• Replace Capacitor Fuse	2
• Change Pump Motor	4
• Re-align Pump	8
• Replace Cable Trench Pump	8
• High Water in Cable Trench	8
• Replace Control Board Component	32
• Replace Control Relay	16
• Replace Control Capacitor	8
• Oscillograph Failure	8
• Replace AC Circuit Breaker	4
• Address Major Relay Failure	80
• Replace DC-DC Converter	8

Based on the above study, the average annual trouble maintenance cost for the Leeds SVC is $14,000/year.

EXHIBIT 28

PROGRAM NAME:

Enhancement of physical security at NY bulk power system substations

PROGRAM DESCRIPTION:

The implementation of state-of-the-art security measures to deter and/or detect unauthorized access to our NY bulk power system substations.

This program will enhance the physical security at The Company's NY bulk power substations beyond current specifications. The installation of visible and evident security measures, such as camera installations and card readers, is intended to deter intrusion. While at the same time, provide the technologies needed to detect intrusions and continuously report them to the security control center.

The proposed security measures are as follows:

- Deployment of card reader technologies at the targeted substations' access points.
-
- State-of-the-art video capabilities connected to remotely monitored cameras.
-
- Remote control of certain lights to illuminate the area in the event of intrusion.
-
- Continuous monitoring of the facility by a security control center.

DRIVER(s):

This strategy is solely driven by the New York Department of Public Service's (DPS) recommendation to install additional physical security measures at our Bulk Power System (BPS) substations in New York. It will comply with the best practices outlined in the October 24, 2008 letter from the Department of Public Service to The Company and reiterated in the Department's letter to The Company, dated August 17, 2009.

As a result of the increase in copper prices over recent years, an increased number of unauthorized trespasses into substations have occurred across the country. In addition to copper theft, vandalism and terrorism could be undertaken by trespassers as well. The Director of Utility Security at the NY Department of Public Services has strongly urged The Company to enhance physical security at its NY BPS substations, pointing out the increase in unauthorized access incidents nationwide, which have occasionally resulted in fatalities.

Trespass into a substation facility where high-voltage equipment is located could result in injury or death to a trespasser who comes in contact with an energized piece of equipment.

Alternatively, intrusion could result in vandalism or damage of electric system equipment such that power is lost or system instability occurs. It is these possibilities that this strategy is proposed to prevent.

The Company's NY BPS substations are already in compliance with the relevant Critical Infrastructure Protection (CIP) requirements, including CIP-006-1a "Physical Security of Critical Cyber Assets". CIP-006-1a seeks to provide "six walled" security around our critical cyber assets. For BPS substations, the six walls usually refer to the control house where the cyber assets are contained. Security measures under CIP-006-1a include card readers and cameras to monitor the ingress and egress points for the control house.

This strategy will provide physical security measures in the substation yard between the Critical Cyber Asset security measures (which encompass the control house) and the outer fence. The outer fence is not required by cyber security requirements.

The objective of the technological solutions' deployment is to deter or detect intrusions. The installation of evident security measures will deter intrusions; however, should an intrusion occur, the solutions deployed would detect it, and initiate the necessary alarms.

OTHER ALTERNATIVES CONSIDERED:

a. Do Nothing

This approach would not alter the current situation. On the other hand, all of the Company's bulk power system substation sites are compliant with existing physical security specifications.

b. Deferral

In the case of a deferral of this investment, the risk that trespassers could enter the property for the purpose of theft or vandalism will still exist. As noted above, customers would potentially experience the consequences of this risk at the time of an incursion. Since the locations considered in this strategy are classified as "Bulk" power substations, any disruption to the flow of power could largely affect the stability of the transmission system and could potentially cause power outages for consumers.

c. Hire 24 hour security guards

This approach would offer a very good deterrence and detection method of intrusion; however, it is substantially costly. It requires background checks and proper training for a certain number of guards for each location in order for them to be able to work in an electric substation environment.. Furthermore, comfort facilities would have to be provided at each guarded substation. Additionally, guard effectiveness would have to be tested periodically to ensure compliance with our security requirements.

d. Man the stations 24 hours per day

Similar to bullet c above, this approach is also very costly. Although, it is considered an effective deterrent method, it does not necessarily guarantee the deterrence and detection of intrusion. Furthermore, the personnel situated at the substations would require proper training to deal with intruders effectively. Also, the potential interaction with intruders would place the substations' personnel at risk.

e. Apply enhanced security measures (recommended)

This approach utilizes evident and visible security measures to deter and detect intrusion. Indeed, noticeable camera installations provide deterrence, since potential trespassers would know that their activities are being monitored and detected. Furthermore, the deployment of technology is less expensive and can be operated on a continuous basis. Advanced video software will analyze the camera data and determine whether an intrusion is a false alarm or not. Linking the security system of each substation with the control center would present the most efficient way of utilizing personnel. Very Few individuals are needed to operate one control room in comparison to the option of having to physically man each individual substation. This approach also meets the three best practices outlined in the October 24, 2008 letter from the Department of Public Service to The Company and reiterated in the Department's letter to The Company dated August 17, 2009.

CUSTOMER BENEFIT(s) OF THE PROGRAM:

This measure secures the system in a world characterized with a sharp and continuous increase in the risk of terrorist threats and criminal acts. The benefits from this strategy arise from deterring and detecting unauthorized access to BPS substations. Benefits to customers include:

1. Reduced likelihood of power loss or equipment unavailability through the prevention of vandalism or theft.
2. Reduction in costs resulting from not having to replace vandalized and stolen station equipment.
3. Reduction of risk to company personnel who could be working in an environment where equipment has been damaged or vandalized.
4. Prevention of lawsuits from people who are injured after entering the property illegally.

METRICS TO TRACK BENEFIT(s):

The success of this strategy will be measured by a reduction in the number of attempts to gain unlawful access into the Company's bulk power system substation sites. A further measure of success will be the number of successful prosecutions where access is made despite the additional surveillance measures.

COSTS AND AVOIDED COSTS:

This strategy is proposed to address unauthorized access attempts to our bulk power substations. The application of security measures will result in an increase of OPEX. This will happen due to O&M demands for equipment as well as a communications infrastructure which provides connectivity between the alarm system and the security control center.

Exhibit 29
Projected Five Year Sub-Transmission Capital Plan- Programs

Spending Rationale	Program	FY10/11	FY 11/12	FY12/13	FY13/14	FY14/15	Total
Asset Condition	Blanket Total	930,000	966,000	995,000	1,031,000	1,050,000	4,972,000
	Open Wire Primary Total	2,000,000	0	0	0	0	2,000,000
	Primary Underground Cable Total	3,000,000	810,000	810,000	0	0	4,620,000
	Substation Capacitor & Switch Total	228,000	200,000	0	0	0	428,000
	Substation Circuit Breaker/Recloser Total	0	300,000	2,640,000	2,800,000	3,019,000	8,759,000
	Substation Indoor Substation Total	659,000	1,925,000	1,800,000	1,800,000	1,800,000	7,984,000
	Substation Metal Clad Switchgear Total	1,250,000	1,900,000	0	0	0	3,150,000
	Substation Power Transformer Total	350,000	40,000	0	0	0	390,000
	Subtransmission and Distribution Tower Total	750,000	2,250,000	3,750,000	5,250,000	5,250,000	17,250,000
	Subtransmission Line Overarching Total	16,036,000	18,065,000	9,700,000	0	0	43,801,000
	Subtransmission Underground Cable Total	500,000	5,864,000	7,028,000	11,615,000	12,693,000	37,700,000
	TBD Total	(1,321,000)	(3,000,000)	(1,689,000)	10,000,000	15,000,000	18,990,000
	Underground/Padmounted Switch Total	500,000	500,000	0	0	0	1,000,000
	Wood Pole Total	150,000	250,000	0	0	0	400,000
Asset Condition Total		**25,032,000**	**30,070,000**	**25,034,000**	**32,496,000**	**38,812,000**	**151,444,000**
Damage/Failure	Damage/Failure Total	3,619,000	3,767,000	3,885,000	3,985,000	4,103,000	19,359,000
Damage/Failure Total		**3,619,000**	**3,767,000**	**3,885,000**	**3,985,000**	**4,103,000**	**19,359,000**
Non - Infrastructure	General Equipment - Dist Total	0		0	0	0	0
	Other Total	0		0	0	0	0
Non - Infrastructure Total		**0**		**0**	**0**	**0**	**0**
Statutory/Regulatory	Inspection & Maintenance Total	9,600,000	10,000,000	10,999,000	11,500,000	11,000,000	53,099,000
	New Business Total	819,000	553,000	574,000	595,000	615,000	3,156,000
	Public Requirements Total	1,289,000	293,000	309,000	316,000	331,000	2,538,000
Statutory/Regulatory Total		**11,708,000**	**10,846,000**	**11,882,000**	**12,411,000**	**11,946,000**	**58,793,000**
System Capacity & Performance	Blanket Total	514,000	528,000	542,000	556,000	569,000	2,709,000
	Distribution & Subtransmssion Automation Total	500,000	1,000,000	2,000,000	4,000,000	5,000,000	12,500,000
	New Business Total	7,260,000		0	0	0	7,260,000
	Planning Criteria Total	1,155,000	5,611,000	13,257,000	7,987,000	7,242,000	35,252,000
	Substation Relay/Protection Total	0	628,000	0	0	0	628,000
	Subtransmission Line Overarching Total	0	250,000	0	0	0	250,000
	TBD Total	(1,788,000)	300,000	1,400,000	3,565,000	4,328,000	7,805,000
System Capacity & Performance Total		**7,641,000**	**8,317,000**	**17,199,000**	**16,108,000**	**17,139,000**	**66,404,000**
Grand Total		**48,000,000**	**53,000,000**	**58,000,000**	**65,000,000**	**72,000,000**	**296,000,000**

Exhibit 30

Projected Five-Year Sub-Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
Asset Condition	Blanket	CNY Sub Trans-Line Asset Replace	CNC075	258,000	268,000	276,000	293,000	291,000	1,386,000	50
		ENY Sub Trans-Line Asset Replace	CNE075	258,000	265,000	272,000	280,000	287,000	1,362,000	50
		WNY Sub Trans-Line Asset Replace	CNW075	414,000	433,000	447,000	458,000	472,000	2,224,000	50
	Blanket Total			**930,000**	**966,000**	**995,000**	**1,031,000**	**1,050,000**	**4,972,000**	
	Open Wire Primary	Trenton Whitesboro 25 Reconductor	C28771	2,000,000	0	0	0	0	2,000,000	39
	Open Wire Primary Total			**2,000,000**	**0**	**0**	**0**	**0**	**2,000,000**	
	Primary Underground Cable	23kV Cable & Conduit Rebuild	C06817	2,500,000		0	0	0	2,500,000	50
		Riv-Part #9 and #37 repl cable	C16079	500,000		0	0	0	500,000	37
		McBride-Brighton Cable Replacement	C31608	0	810,000	810,000	0	0	1,620,000	34
	Primary Underground Cable Total			**3,000,000**	**810,000**	**810,000**	**0**	**0**	**4,620,000**	
	Substation Capacitor & Switch	Homer Hill Sta - Rep Cap Bank & Bkr	C15660	0	200,000	0	0	0	200,000	24
		Brockport 74-Cap banks to sta bus	C26382	228,000	0	0	0	0	228,000	36
	Substation Capacitor & Switch Total			**228,000**	**200,000**	**0**	**0**	**0**	**428,000**	
	Substation Circuit Breaker/Recloser	ARP Breakers & Reclosers - Sub-T sub	C3B&R	0	300,000	2,640,000	2,800,000	3,019,000	8,759,000	(blank)
	Substation Circuit Breaker/Recloser Total			**0**	**300,000**	**2,640,000**	**2,800,000**	**3,019,000**	**8,759,000**	
	Substation Indoor Substation	Buffalo Station 29 Rebuild - 23 kV	C06724	89,000		0	0	0	89,000	41
		Buffalo Station 43 Rebuild - 23kV	C27945	70,000	125,000	0	0	0	195,000	41
		Buffalo Station 52 Rebuild - 23 kV	C27946	200,000		0	0	0	200,000	41
		Buffalo Station 27 Rebuild - 23 kV	C33470	100,000	500,000	0	0	0	600,000	50
		Buffalo Station 37 Rebuild - 23 kV	C33471	100,000	500,000	0	0	0	600,000	50
		Buffalo Station 59 Rebuild - 23 kV	C33472	100,000	500,000	0	0	0	600,000	50
		Buffalo Station 25 Rebuild - 23 kV	CBUF25-1	0	100,000	500,000	0	0	600,000	41
		Buffalo Station 30 Rebuild - 23 kV	CBUF30-1	0		0	100,000	500,000	600,000	41
		Buffalo Station 31 Rebuild - 23 kV	CBUF31-1	0		100,000	500,000	0	600,000	41
		Buffalo Station 32 Rebuild - 23 kV	CBUF32-1	0	100,000	500,000	0	0	600,000	41
		Buffalo Station 34 Rebuild - 23 kV	CBUF34-1	0		100,000	500,000	0	600,000	41
		Buffalo Station 35 Rebuild - 23 kV	CBUF35-1	0		0	100,000	500,000	600,000	41
		Buffalo Station 38 Rebuild - 23 kV	CBUF38-1	0		0	0	100,000	100,000	41
		Buffalo Station 41 Rebuild - 23 kV	CBUF41-1	0		0	100,000	500,000	600,000	41
		Buffalo Station 45 Rebuild - 23 kV	CBUF45-1	0		0	0	100,000	100,000	41
		Buffalo Station 51 Rebuild - 23 kV	CBUF51-1	0		100,000	500,000	0	600,000	41
		Buffalo Station 53 Rebuild - 23 kV	CBUF53-1	0	100,000	500,000	0	0	600,000	41
		Buffalo Station 68 Rebuild - 23 kV	CBUF68-1	0		0	0	100,000	100,000	41
	Substation Indoor Substation Total			**659,000**	**1,925,000**	**1,800,000**	**1,800,000**	**1,800,000**	**7,984,000**	
	Substation Metal Clad Switchgear	Replace/Relocate 13.8kV SG @Oneida	C25139	300,000	1,900,000	0	0	0	2,200,000	50
		North Troy Metal Clad Repl.	C28485	950,000		0	0	0	950,000	39
	Substation Metal Clad Switchgear Total			**1,250,000**	**1,900,000**	**0**	**0**	**0**	**3,150,000**	
	Substation Power Transformer	Buffalo Shunt Reactors	C03831	350,000	40,000	0	0	0	390,000	50
	Substation Power Transformer Total			**350,000**	**40,000**	**0**	**0**	**0**	**390,000**	
	Subtransmission and Distribution Tower	IE - NE SubT Towers	C31852	250,000	750,000	1,250,000	1,750,000	1,750,000	5,750,000	40
		IE - NC SubT Towers	C31853	250,000	750,000	1,250,000	1,750,000	1,750,000	5,750,000	40
		IE - NW SubT Towers	C31855	250,000	750,000	1,250,000	1,750,000	1,750,000	5,750,000	40
	Subtransmission and Distribution Tower Total			**750,000**	**2,250,000**	**3,750,000**	**5,250,000**	**5,250,000**	**17,250,000**	
	Subtransmission Line Overarching	Schuyler-Valley 21/24	C00413	1,000,000		0	0	0	1,000,000	20
		Charlton-Ballston #9 Rebuild/Recnfg	C06739	0	1,000,000	0	0	0	1,000,000	22
		Greenbush-Defreesville 7 Rebuild	C07519	0	1,000,000	0	0	0	1,000,000	27
		Rathbun-Labrador #39 Rebuild	C07804	1,000,000	1,000,000	0	0	0	2,000,000	43
		Tilden-Tully #24 34.5kV Rebuild	C07811	1,000,000		0	0	0	1,000,000	42
		Lowville-Boonville #22 Rebuild	C07814	1,500,000		0	0	0	1,500,000	50
		McClellan-Bevis #11 34.5kV Rebuild	C11818	700,000		0	0	0	700,000	30
		Marshville-Cherry Vly LN4 Retiremnt	C12678	1,000		0	0	0	1,000	50
		Lake Clear-Tupper Lake #38 Rebuild	C13046	1,000,000	2,000,000	1,000,000	0	0	4,000,000	50
		Maplewood-Latham #9 Refurb	C16072	400,000		0	0	0	400,000	30
		Newtonville-Patroon #16 Refurb	C16073	0	1,300,000	0	0	0	1,300,000	30
		Vischer - Woodlawn #3 refurbish	C16234	100,000		0	0	0	100,000	40
		Gloversville - Canaj. #6 Refurbish	C16236	0	1,000,000	1,000,000	0	0	2,000,000	27
		Gloversville-Hill St #3 Refurbish	C16237	100,000		0	0	0	100,000	23
		Batavia-Attica 206-34.5kv	C25940	2,500,000	500,000	0	0	0	3,000,000	34
		Greenbush-Rensselaer#10&#11 Rebuild	C26636	125,000		0	0	0	125,000	50
		Bombay-Spencer's Corners#22 Recond	C26969	500,000		0	0	0	500,000	34
		General Mills-Ridge 611/612 Ohio Sw	C27223	0	450,000	0	0	0	450,000	30
		Oakfield-Caledonia 201-34.5kv Rbld.	C27438	0	0	0	0	0	0	40
		N Angola - Bagdad 862 Refurbishment	C27502	230,000	0	0	0	0	230,000	34
		N Leroy - Attica 208 Refurbishment	C27562	1,100,000	1,000,000	0	0	0	2,100,000	50
		Medina-Albion 305 Refurbishment	C27563	100,000	0	0	0	0	100,000	34

Exhibit 30
Projected Five-Year Sub-Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		Battenkill-Cambridge 2/5 Refurbish	C27564	1,100,000	1,000,000	0	0	0	2,100,000	34
		Beth-Voorheesville-Retire Callanan	C27582	100,000	300,000	0	0	0	400,000	50
		Spier-Glens Falls 8-pls	C27583	0	750,000	500,000	0	0	1,250,000	34
		Caledonia-Golah 213-refurbish	C27586	1,800,000		0	0	0	1,800,000	50
		Trenton-Deerfield 21/27-46kv	C28017	750,000	0	0	0	0	750,000	34
		Market Hill-Amsterdam 11,Tap Mohasc	C28018	0	30,000	0	0	0	30,000	26
		WHTESBR-SCHUYLER 29/YAH-WHITSBRO 23	C28942	450,000		0	0	0	450,000	45
		Carthage-N.Carthage 24/28 Refurbish	C29441	0	500,000	0	0	0	500,000	34
		Norfolk-Norwood 23kv	C29443	0	500,000	0	0	0	500,000	34
		Hartfield-Sherman 855-refurbish	C29450	100,000	700,000	0	0	0	800,000	42
		W. Salamanca-Homer Hill 805 ref	C29451	100,000	700,000	0	0	0	800,000	42
		Crescent -School St/N. Troy 17/20	C29452	100,000		0	0	0	100,000	50
		Relocate and tap Line 856 to ECWA	C29485	50,000		0	0	0	50,000	50
		Lines 611,612,613 Arrestors-34.5kv	C29768	0	650,000	0	0	0	650,000	27
		Alder Creek-Old Forge #23 46kV	C31263	30,000		0	0	0	30,000	42
		Albion - Brockport 308 Rebuild	C33131	50,000	1,500,000	0	0	0	1,550,000	34
		Yahnundasis-Schuyler 25/26 Rebuild	C33174	0	50,000	1,500,000	0	0	1,550,000	42
		Youngmann 605/606 Rebuild	C33178	50,000	1,000,000	0	0	0	1,050,000	42
		Hartfield-S. Dow 859 Rebuild	C33180	0	50,000	1,000,000	0	0	1,050,000	42
		Ransom-Phillips Rd 402 Rebuild	C33181	0	50,000	1,500,000	0	0	1,550,000	42
		Amsterdam-Rotterdam 3/4 Relocation	C33182	0	250,000	2,000,000	0	0	2,250,000	34
		Niagara Falls Remove 12kV Lines	C33191	0	35,000	450,000	0	0	485,000	42
		Hartfield-Ashvile 854 Refurbish	C33294	0	750,000	750,000	0	0	1,500,000	42
	Subtransmission Line Overarching Total			**16,036,000**	**18,065,000**	**9,700,000**	**0**	**0**	**43,801,000**	
	Subtransmission Underground Cable	IE - NE Sub-T UG Cable Replacement	C32146	250,000	864,000	538,000	1,170,000	900,000	3,722,000	36
		IE - NC Sub-T UG Cable Replacement	C32147	0		990,000	945,000	793,000	2,728,000	36
		IE - NW Sub-T UG Cable Replacement	C32148	250,000	5,000,000	5,500,000	9,500,000	11,000,000	31,250,000	36
	Subtransmission Underground Cable Total			**500,000**	**5,864,000**	**7,028,000**	**11,615,000**	**12,693,000**	**37,700,000**	
	TBD	TxD RESERVE for Asset Replacement Unidentified Specifics	RESERVE 036_017 I	(1,071,000)	(3,000,000)	(1,689,000)	10,000,000	15,000,000	19,240,000	0
		TxD RESERVE for Asset Replacement Unidentified Specifics	RESERVE 036_017 S	(250,000)	0	0	0	0	(250,000)	34
	TBD Total			**(1,321,000)**	**(3,000,000)**	**(1,689,000)**	**10,000,000**	**15,000,000**	**18,990,000**	
	Underground/Padmounted Switch	L630 & 631 Hendrix Ca + LBSwitches	C17668	500,000	500,000	0	0	0	1,000,000	36
	Underground/Padmounted Switch Total			**500,000**	**500,000**	**0**	**0**	**0**	**1,000,000**	
	Wood Pole	Tonawanda 601/603 Pole Replacements	C31577	150,000	250,000	0	0	0	400,000	42
	Wood Pole Total			**150,000**	**250,000**	**0**	**0**	**0**	**400,000**	
Asset Condition Total				**25,032,000**	**30,070,000**	**25,034,000**	**32,496,000**	**38,812,000**	**151,444,000**	
Damage/Failure	Damage/Failure	CNY Sub Trans-Line Damage Failure	CNC073	613,000	628,000	641,000	655,000	669,000	3,206,000	50
		CNY Sub Trans-Substation Blanket	CNC074	318,000	350,000	368,000	376,000	394,000	1,806,000	50
		ENY Sub Trans-Line Damage Failure	CNE073	827,000	859,000	886,000	911,000	938,000	4,421,000	50
		ENY Sub Trans-Substation Blanket	CNE074	107,000	117,000	123,000	126,000	132,000	605,000	50
		WNY Sub Trans-Line Damage Failure	CNW073	1,647,000	1,694,000	1,741,000	1,788,000	1,835,000	8,705,000	50
		WNY Sub Trans-Substation Blanket	CNW074	107,000	119,000	126,000	129,000	135,000	616,000	50
		TxD RESERVE for Damage/Failure Unidentified Specifics &	RESERVE 036_014 I	0		0	0	0	0	50
		TxD RESERVE for Damage/Failure Unidentified Specifics &	RESERVE 036_014 S	0		0	0	0	0	50
	Damage/Failure Total			**3,619,000**	**3,767,000**	**3,885,000**	**3,985,000**	**4,103,000**	**19,359,000**	
Damage/Failure Total				**3,619,000**	**3,767,000**	**3,885,000**	**3,985,000**	**4,103,000**	**19,359,000**	
Statutory/Regulatory	Inspection & Maintenance	FH - NE SubT Work Found by Insp.	C26165	3,200,000	3,333,000	3,666,000	3,833,000	3,666,000	17,698,000	42
		FH - NC SubT Work Found by Insp.	C26166	3,200,000	3,333,000	3,666,000	3,833,000	3,667,000	17,699,000	42
		FH - NW SubT Work Found by Insp.	C26167	3,200,000	3,334,000	3,667,000	3,834,000	3,667,000	17,702,000	42
		FH - NE SubT Work Found by Insp.	E07215	0		0	0	0	0	42
		FH - NC SubT Work Found by Insp.	E07216	0		0	0	0	0	42
		FH - NW SubT Work Found by Insp.	E07217	0		0	0	0	0	42
	Inspection & Maintenance Total			**9,600,000**	**10,000,000**	**10,999,000**	**11,500,000**	**11,000,000**	**53,099,000**	
	New Business	NE-Great Escape	C23713	8,000		0	0	0	8,000	50
		34.5kv Tap to Chau. Co. Lndfill-nug	C30409	140,000		0	0	0	140,000	50
		New 23kV Cables - New Kaleida Stat.	C32813	140,000		0	0	0	140,000	50
		CNY Sub Trans-Line New Business	CNC071	220,000	230,000	240,000	250,000	260,000	1,200,000	50
		ENY Sub Trans-Line New Business	CNE071	104,000	109,000	113,000	117,000	121,000	564,000	50
		WNY Sub Trans-Line New Business	CNW071	207,000	214,000	221,000	228,000	234,000	1,104,000	50
		TxD RESERVE for New Business Residential Unidentified Sp	RESERVE 036_010 I	0		0	0	0	0	50
		TxD RESERVE for New Business Commercial Unidentified S	RESERVE 036_011 I	0		0	0	0	0	50
	New Business Total			**819,000**	**553,000**	**574,000**	**595,000**	**615,000**	**3,156,000**	
	Public Requirements	NYSDOTR Rt28 Woodgate to McKeever	C26405	1,000,000		0	0	0	1,000,000	50
		Sub-T Reimb Glenridge Rd	C31180	25,000		0	0	0	25,000	50
		CNY Sub Trans-Line Public Require	CNC072	84,000	93,000	98,000	100,000	105,000	480,000	50
		ENY Sub Trans-Line Public Require	CNE072	138,000	153,000	161,000	165,000	173,000	790,000	50
		WNY Sub Trans-Line Public Require	CNW072	42,000	47,000	50,000	51,000	53,000	243,000	50

Exhibit 30

Projected Five-Year Sub-Transmission Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		TxD RESERVE for Public Requirements Unidentified Specifi	RESERVE 036_013 I	0		0	0	0	0	50
	Public Requirements Total			**1,289,000**	**293,000**	**309,000**	**316,000**	**331,000**	**2,538,000**	
Statutory/Regulatory Total				**11,708,000**	**10,846,000**	**11,882,000**	**12,411,000**	**11,946,000**	**58,793,000**	
System Capacity & Performance	Blanket	CNY Sub Trans-Line Reliability	CNC076	128,000	130,000	133,000	136,000	138,000	665,000	50
		ENY Sub Trans-Line Reliability	CNE076	103,000	106,000	109,000	112,000	115,000	545,000	50
		WNY Sub Trans-Line Reliability	CNW076	283,000	292,000	300,000	308,000	316,000	1,499,000	50
	Blanket Total			**514,000**	**528,000**	**542,000**	**556,000**	**569,000**	**2,709,000**	
	Distribution & Subtransmssion Automation	Sub-Transmission Line Sectionalizing	CLINESEC	500,000	1,000,000	2,000,000	4,000,000	5,000,000	12,500,000	(blank)
	Distribution & Subtransmssion Automation Total			**500,000**	**1,000,000**	**2,000,000**	**4,000,000**	**5,000,000**	**12,500,000**	
	New Business	Buffalo Niagara Medical Campus-Sub	C31665	2,650,000		0	0	0	2,650,000	47
		Buffalo Niagara Medical Campus-Line	C31666	4,610,000		0	0	0	4,610,000	47
	New Business Total			**7,260,000**		**0**	**0**	**0**	**7,260,000**	
	Planning Criteria	NY SubT PS&I Activity	C08154	100,000	105,000	110,000	115,000	120,000	550,000	36
		Reynolds - Add M/C & Equip	C26419	0	1,100,000	0	0	0	1,100,000	36
		Buffalo 23kV Reconductor - Huntley	C28892	150,000	1,000,000	6,200,000	0	0	7,350,000	36
		Buffalo 23kV Reconductor - Huntley2	C28893	150,000	1,000,000	1,200,000	0	0	2,350,000	36
		Buffalo 23kV Reconductor - Kensing.	C28894	0	500,000	2,300,000	0	0	2,800,000	30
		Buffalo 23kV Reconductor - Kens2	C28903	0	800,000	1,300,000	0	0	2,100,000	30
		Seneca - Replace Series Reactors	C29100	1,100,000		0	0	0	1,100,000	44
		Beth-AveA #10 - reconductor	C31951	0	300,000	2,000,000	0	0	2,300,000	30
		Delaware-Bethlehem 14 - Reconductor	C31952	0	300,000	1,300,000	0	0	1,600,000	30
		CNY Sub Trans-Line Load Relief	CNC077	49,000	52,000	54,000	56,000	58,000	269,000	50
		ENY Sub Trans-Line Load Relief	CNE077	28,000	29,000	30,000	31,000	32,000	150,000	50
		WNY Sub Trans-Line Load Relief	CNW077	28,000	29,000	30,000	31,000	32,000	150,000	50
		TxD RESERVE for Load Relief Unidentified Specifics & Sche	RESERVE 036_016 I	0		(2,900,000)	6,000,000	5,000,000	8,100,000	34
		TxD RESERVE for Load Relief Unidentified Specifics & Sche	RESERVE 036_016 S	(450,000)	396,000	1,633,000	1,754,000	2,000,000	5,333,000	34
	Planning Criteria Total			**1,155,000**	**5,611,000**	**13,257,000**	**7,987,000**	**7,242,000**	**35,252,000**	
	Substation Relay/Protection	Teall Ave Upgrade 34.5kV Protection	C07808	0	628,000	0	0	0	628,000	24
	Substation Relay/Protection Total			**0**	**628,000**	**0**	**0**	**0**	**628,000**	
	Subtransmission Line Overarching	Alder Creek 46kV Sta Bypass	C32216	0	250,000	0	0	0	250,000	34
	Subtransmission Line Overarching Total			**0**	**250,000**	**0**	**0**	**0**	**250,000**	
	TBD	TxD RESERVE for Reliability Unidentified Specifics & Sched	RESERVE 036_015 I	(1,178,000)	0	300,000	2,365,000	2,928,000	4,415,000	0
		TxD RESERVE for Reliability Unidentified Specifics & Sched	RESERVE 036_015 S	(610,000)	300,000	1,100,000	1,200,000	1,400,000	3,390,000	34
	TBD Total			**(1,788,000)**	**300,000**	**1,400,000**	**3,565,000**	**4,328,000**	**7,805,000**	
System Capacity & Performance Total				**7,641,000**	**8,317,000**	**17,199,000**	**16,108,000**	**17,139,000**	**66,404,000**	
Non-Infrastructure	General Equipment - Dist	TxD RESERVE for General Equipment Specifics & Schedule	RESERVE 036_070 I	0		0	0	0	0	34
	General Equipment - Dist Total			**0**		**0**	**0**	**0**	**0**	
	Other	TxD RESERVE for Other Unidentified Specifics & Schedule (	RESERVE 036_999 I	0		0	0	0	0	34
		TxD RESERVE for Other Unidentified Specifics & Schedule (	RESERVE 036_999 S	0		0	0	0	0	34
	Other Total			**0**		**0**	**0**	**0**	**0**	
Non-Infrastructure Total				**0**		**0**	**0**	**0**	**0**	
Grand Total				**48,000,000**	**53,000,000**	**58,000,000**	**65,000,000**	**72,000,000**	**296,000,000**	

nationalgrid

EXHIBIT 31

PROGRAM NAME:

Inspection and Maintenance Program (I&M)

PROGRAM DESCRIPTION:

Under this program, the Company will inspect all electric line assets (Distribution Overhead, Underground, and Sub Transmission line assets) once every five years. Each inspection will identify and categorize all necessary repairs (or asset replacement) in terms of urgency to improve the reliability of the network for customers. Any repair work identified as a result of the Inspection and Maintenance program will be prioritized based on the severity of the issues found and incorporated into the work plan as appropriate. Priority Codes are as follows:

Level 1-	Must be repaired/replaced within one week
Level 2-	Must be repaired/replaced within one year
Level 3-	Must be repaired/replaced within three years
Level 4-	Information only, replace based on engineering judgment and budget availability

As part of this program, the Company will perform visual inspections of overhead, underground, and sub-transmission lines and aerial inspections of sub-transmission lines. The Company will also perform infrared inspections of overhead distribution mainline sections of the feeders and separable components on underground equipment.

This program will subsume some of the existing strategies program work such as Feeder Hardening Program, Potted porcelain Cutouts, Targeted pole replacements, Miscellaneous Overhead, miscellaneous underground, Manholes, and Vaults.

The Company will also perform annual elevated voltage testing on all facilities that are capable of conducting electricity and are publicly accessible such as street lights.

DRIVER(s):

This program is designed to

- improve the reliability of the electric distribution network based on a condition assessment,
- improve the safety of customers and employees by identifying and addressing locations with elevated voltage
- improve the efficiency of T&D service by optimizing the timing of maintenance activities and asset replacements.

- meet the mandated requirements set forth by the PSC and provide for a sustainable distribution and sub-transmission system
- formalizing the existing differing practices across the company into one consistent approach

OTHER ALTERNATIVES CONSIDERED:

The “I&M” is a subset of the Reliability Enhancement Program (REP), which was developed in 2007 to improve the reliability of the system. Feeder Hardening was developed to specifically address overhead deteriorated equipment and lightning related interruptions on distribution feeders. Feeder Hardening utilizes remediation measures, such as replacement of fuse cutouts, crossarms, poles and transformers; lightning protection with bonding, grounding and lightning arrester installations; and installation of animal guards. Feeder Hardening program is much smaller scaled program compared to the new I&M program since it was designed to specifically address the reliability of specific feeders. Having a larger scale I&M program will ensure that every asset is proactively inspected and maintained in the scheduled cycle.

CUSTOMER BENEFIT(s) OF PROGRAM:

The Inspection and Maintenance Program is designed to sharply reduce the number of interruptions due to deteriorated equipment, animals and lightening on the Company’s overhead distribution and sub-T system based on a periodic condition assessment. The program will also minimize the likelihood of replacing assets that do not need replacing. By optimizing the timing of maintenance activities and asset replacements, the Company will improve the efficiency of its T&D service

Over the past four years, almost 25% of the SAIFI metric was due to interruptions along the distribution network caused by deteriorated equipment (16%), animals (3%) and lightening (7%). Interruptions along the sub-transmission network accounted for another 7% of SAIFI. The approximate average annualized expected benefits for implementing the Inspection and Maintenance program would be a reduction of 0.02 in SAIFI and 2.64 in SAIDI.

Safety is another key driver for the Inspection and maintenance program. The Inspection and Maintenance Program is designed identify and eliminate elevated voltage levels on the Company’s facilities that are capable of conducting electricity and publicly accessible. Therefore, the main customer and employee safety benefit from this strategy is the elimination of elevated voltage hazards.

METRICS TO TRACK BENEFIT(s):

- SAIFI and CAIDI metric for deteriorated equipment, lightning and animals
- Amount of spending to repair outages due to failed equipment, animals or lightning.
- Injuries due to elevated voltage

EXHIBIT 32

PROGRAM NAME:

Sub Transmission Line Overarching

PROGRAM DESCRIPTION:

This program represents a consolidated strategy pursuant to which the Company plans to refurbish and/or replace sub-transmission overhead lines and their associated assets to ensure the sub transmission system continues to operate in a safe and reliable manner for the foreseeable future.

In support of these goals, a number of projects have already been identified and are included in the budget for delivery in FY11 to FY15

DRIVER(s):

The main driver for this consolidated program is maintaining the reliability of the electric network, based on an assessment of asset conditions. The The Company Sub-Transmission system is aging and deteriorating; on-going repairs and refurbishments for overhead line assets are reactive in nature. Many sub-transmission line assets are of an age which exceeds their original design life of between 40 and 60 years.

A program to proactively manage asset conditions in the future is necessary to ensure that the Sub-Transmission system provides the level of service expected and required.

As can be seen from the table below, there is significant asset base in the Sub Transmission line category.

Sub-Transmission Line Asset Types and Inventory

Sub Transmission Line Main Assets	Inventory
Towers	3,800
Poles	60,600
Line Circuit Miles	3,400 miles

There are nearly 3,800 sub-transmission steel structures, most of which are 60 to 90 years old. Towers will normally be refurbished in a timely manner rather than replaced. This approach will minimize both the costs and outage requirements associated with wholesale replacement. However, there comes a point at which so many steel bars require replacement that it is more economical to replace the whole tower.

Of all pole failure-related outages, nearly one-third occur on the sub-transmission system. Furthermore, these outages account for 40% of the SAIDI caused by pole failures. The Company plans to maintain or improve pole age profile in order to mitigate any possible failure rate increases in the future. Poles will be replaced based on their conditions, as identified through the inspection and maintenance process.

The Company has no specific strategy to replace sub-transmission conductors, however, the engineering department evaluates conductors smaller than 1/0 Cu during refurbishment projects and some conductors will be replaced at the same time as pole replacements, if necessary due to condition. Reconductoring will also be performed as part of pole replacement projects, if a planning study identifies conductors near their thermal limit.

Sub-transmission Line Insulators cause significant concern. These assets account for 40% of the SAIFI and 50% of the SAIDI for all failed insulator-related outages. While most of the SAIFI is due to failed insulators on 13.2kV lines, the leading SAIDI driver occurs on 34.5kV sub-transmission lines.

Line refurbishments can include replacement of all or part of all line components including structures, insulators, cross arms, guys and anchors, switches, and small sections of conductor and overhead ground wire.

The poor or deteriorated condition of some steel tower foundations also gives rise to concerns for tower integrity to withstand the mechanical stresses imposed. particularly during times of high wind or ice loading. The Company is currently developing a program that will commence in FY2011.

In addition, The Company has extensive rights of ways relating to the sub-transmission overhead lines. A program to address issues related to vegetation in these rights of ways was initiated in 2007 based on the top lines impacting Customer Minutes Interrupted, which is targeted to finish in 2012.

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Do Nothing

The Company could do nothing and allow assets to further deteriorate. This option would diminish the level of service provided to customers, and reduce the overall reliability of the sub-transmission and distribution system.

Option 2 – Fix or Replace on Failure

This option would have a negative impact on the level of service provided to customers and to the overall reliability of the system as a reactive approach is both inefficient and may lead to multiple outages.

In any reactive approach we are more likely to see the failure and collapse of subtransmission lines

CUSTOMER BENEFIT(s) OF PROGRAM:

Sub-transmission line assets are a key component of the energy delivery system. Because of this characteristic, any asset-related issue may potentially impact a large number of customers.

Currently on-going repairs and refurbishment projects are reactive in nature. The determination of specific problems projects on sub-transmission lines are determined by Computapole inspections, engineering field inspections, aerial flyover data, and other information that is available—including such as revised standards, infrared inspections and customer complaints. Therefore, a program to proactively manage condition in future is necessary to ensure that the sub-transmission system is able to provide the level of service expected and required.

Safety and Environmental

Implementation of this program will address safety concerns relating to conductor and insulator failures, tower condition and the integrity of some foundations.

Reliability

Over the last ten years sub transmission insulators accounted for 40% of the SAIFI and 50% of the SAIDI for all failed insulator-related outages. This program will result in improved reliability of the sub-transmission overhead network. In particular, it will address a significant reliability issue associated with insulators, as part of this replacement program. Nearly one-third of all pole failure-related outages occur on the sub transmission system. Furthermore, these outages account for 40% of the SAIDI caused by pole failures.

Customer / Regulatory / Reputation

This strategy will enhance our customer/regulatory/reputation as it demonstrates we have a proactive approach to the management of this asset class.

Efficiency

The implementation of a planned refurbishment/replacement program will ensure better visibility of projects for the purpose of budgeting and will ensure the sub transmission system continues to deliver in a safe and reliable manner for the foreseeable future.

METRICS TO TRACK BENEFIT(s):

The use of SAIDI, SAIFI and CAIDI will aid in tracking the benefit(s) of the sub-transmission line refurbishment / replacement programs.

In addition, the Inspection and Maintenance (I&M) program will both maintain and improve the reliability of electric service on a cost effective basis that leads to a longer-term planning horizon, providing the opportunity to more efficiently procure and allocate needed resources.

EXHIBIT 33

PROGRAM NAME:

Distribution and Sub-transmission Underground Cable

PROGRAM DESCRIPTION:

The Distribution and Sub-transmission Underground Cable asset replacement program replaces cables that are in poor condition. Currently, The Company separates the distribution program from the sub-transmission program. A common program is currently being devised which will apply new technologies proactively, and address replacements with priorities determined by condition and risk.

DRIVER(s):

Asset Condition

As noted in the Report on the Condition of Physical Elements on Transmission and Distribution Systems filed on October 1, 2009 in Case No. 06-M-0878, more than half of the 1,100 miles of subtransmission cables are greater than 47 years old; one third are greater than 60 years old. Because of heavy networking in the system, sub-transmission cables do not usually impact reliability. However, the age of these assets results in significant repair activities – also described in the Report. An example is Buffalo cable repairs 2005-2008:

Year	2005	2006	2007	2008
Number of repairs	80	38	43	63

In addition, particular cable types (lead, XLPE) show a greater level of deterioration than similar cables of the same vintage.[137]

System Performance & Reliability

Over the 10 year period from 1999-2008, underground cables were the third highest contributor to deteriorated equipment SAID/SAIFI, with individual annual average contributions of 0.016 SAIFI and 2.16 minutes SAIDI.

[137] Industry awareness of XLPE cable issues and neutral conductor deterioration has been documented in many places.

OTHER ALTERNATIVES CONSIDERED:

The only other alternative to this strategy is a fix-on-fail approach. The Company rejected this option because it would significantly increase the possibility of contingent failures to networked cables.

CUSTOMER BENEFIT(s) OF PROGRAM:

Through a more proactive approach to cable condition analysis and preventative work, a program may reduce the impact of failures by 50 percent over 5 years

This gives an annual improvement of 10 percent of the current impact, or 0.0016 SAIFI and 0.216 minutes SAIDI.

METRICS TO TRACK BENEFIT(s):

Value of replacement may be calculated through measured improvements in SAIDI/SAIFI.

The volume of cables in poor condition cable, as identified by novel test and assessment techniques, should indicate whether capital is being directed efficiently.

EXHIBIT 34

PROGRAM NAME:

Sub Transmission & Distribution Tower

PROGRAM DESCRIPTION:

This strategy is focused on sustainability. It is designed to prevent steel members and foundations from deteriorating to the point of structural failure under expected mechanical loading or becoming weak to the point of compromised safety.

DRIVER(s):

The strategy is currently under development for this asset class.

> There are nearly 3,800 sub-transmission steel structures, most of which are 60 to 90 years old. The original design life (without preventative maintenance) was anticipated to be in the region of 40 to 60 years.
>
> Towers naturally suffer from the natural life limiting process of corrosion. A tower may reach the end of life when so many steel members require changing, welding repair or painting that it becomes more economic to replace the whole tower. Alternatively, a tower may reach the end of useful life when it becomes unsafe to work on the tower (note – the erection loads seen during reconductoring are more onerous than everyday loads).

The poor or deteriorated condition of some steel tower foundations also give rise to concerns for the integrity of the tower to withstand the mechanical stresses imposed, particularly during times of high wind or ice loading. The Company is currently developing a maintenance and refurbishment program for steel line structures commencing in FY2011.

> While the age-related life limiting process for tower foundations may be unknown for a well maintained tower, The Company expects to scrap a tower's foundations once the tower has reached the end of its life. Hence, foundation lives are directly linked to and limited by the tower structure (painted to policy) lives.

Interruptions caused by tower related issues, although infrequent, can be significant. Towers in the poorest condition face a higher risk of storm damage and possibly safety-related issues, as demonstrated by the cascade failure of 15 double circuit towers on the 12kV system adjacent to Packard Road in Niagara Falls at the beginning of November 2009.

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Do Nothing

The Company may do nothing and allow assets to further deteriorate. This option would have a negative impact on the level of service provided to our customers and to the overall reliability of the sub transmission and distribution system.

Option 2 – Fix or Replace on Failure

The Company may wait until a tower's failure to repair or replace it. This option would have a negative impact on the level of service provided to our customers and to the overall reliability of the sub-transmission and distribution system.

CUSTOMER BENEFIT(s) OF PROGRAM:

Sub-transmission line assets are a key component of the energy delivery system. Because of this, any asset related issue has the potential to affect a large number of customers.

Currently, on-going repairs and refurbishment projects are reactive in nature. The present determination of specific problems projects on sub-transmission towers are determined by Computapole inspections, engineering field inspections, aerial flyover data, and other information that is available--including revised standards, infrared inspections and customer complaints. Therefore, a program to proactively manage conditions is necessary to ensure that the Sub-Transmission system provides the level of service expected and required.

<u>Safety and Environmental</u>

Tower replacements prior to failure or partial failure provide improved safety benefits. Badly corroded steel members have reduced mechanical strength due to reduced cross-sectional area, compared to well-maintained and corrosion-free components. This 'reduced' strength could result in an increased risk of failure during activities requiring access to the tower or during extreme weather events.

<u>Reliability</u>

Sub transmission line assets are a key component of the energy delivery system. The reliability benefit associated with tower replacement is negligible , since outages on the sub transmission network typically do not directly impact customers. However, in some cases, extended outages can occur. The most benefit relative to refurbishment is likely to be realized during significant weather events of high winds or heavy ice and snow. These major weather events often result in regulatory exclusion. Replacement of corroded steel components in a 'controlled' and 'planned' manner should require shorter periods of access to that tower.

Customer / Regulatory / Reputation

This strategy will likely have a positive (although not measurable) impact on customers' perceptions that the system is properly maintained. Customers often see these structures while driving along nearby roads. Rusting towers or structures with broken components are quickly noticed and provide a perception of how well the system is maintained.

Efficiency

The implementation of a planned refurbishment/replacement program will ensure better visibility of projects for the purpose of budgeting and will ensure the sub transmission system continues to deliver in a safe and reliable manner for the foreseeable future.

METRICS TO TRACK BENEFIT(s):

The use of SAIDI, SAIFI and CAIDI will aid in tracking the benefit(s) of the sub transmission line refurbishment / replacement programs.

EXHIBIT 35

PROGRAM NAME:

Substation Metal Clad Switchgear

PROGRAM DESCRIPTION:

This program addresses the replacement of poor condition metal clad switchgear based on:

- Visual and operational inspection results
- Electro-acoustic test results
- Performance history

Metalclad equipment is prone to rusting and animal ingress which leads to moisture and dust-related or animal-related failures. Bimonthly Visual and Operational ("V&O") Surveys help detect such degradation. Yet such failures do not identify poorly performing electrical equipment unless significant deterioration or failure occurs, because insulation issues remain hidden and surface tracking is undetectable through visual inspection.

Detection and identification of electrical equipment degradation may be performed using electro-acoustic detection techniques to detect anomalous sound (acoustic) waves or electric signals in the metal clad. These methods make it possible to detect incipient failures before they reach a point where they become practical failures.

Replacement of Springfield and North Troy metal clad stations has been initiated; Ash Street, Oneida and Market Hill are at an initial planning stage while Guy Park is being engineered at present.

Electro-acoustic surveys are planned to support on-going preventative maintenance and V&O Surveys, as The Company pursues a proactive approach to condition-based metal clad management. The initial review using this technique identified a number of locations where minor repairs or refurbishments were recommended. The review also identified another 22 substations (out of a population of approximately 220) that required major repairs or refurbishments. The appendix below details the results of the survey.

DRIVER(s):

Several design factors with older vintage metalclad substations contribute to bus failures or component failures. These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the failures of metal-clad switch-gear, substations and busses. Gaskets and caulking of enclosures deteriorate over time allowing rain and melting snow to enter.

- Ventilation - Metalclad interiors can reach high temperatures in the summer even if ventilation systems work correctly. High temperatures degrade the lubrication in breaker mechanisms and other moving parts, and can cause failure of electronic controls and relays
- Insulation - Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages, appear in earlier vintage switchgear. This strategy would replace two metalclad substations per year using age and manufacturer as a proxy to conduct condition assessment.

The replacement program addresses poorly performing equipment. Individual failures may be uncommon, but the effects, as at Ash Street and at North Troy, may be substantial in terms of customer interruptions.

OTHER ALTERNATIVES CONSIDERED:

Option 1 - Fix on Failure

The "fix on fail" approach means The Company will be significantly more likely to experience further extended interruptions similar to that caused by the North Troy incident.

Option 2- Age Based Consideration Only

Relying solely on age-based considerations is an inefficient way to target replacement candidates. Considerable knowledge may be gained for prioritization of replacements by supplementing V&O Surveys with electro acoustic surveys.

CUSTOMER BENEFIT(s) OF PROGRAM:

Reliability – Metal clad failures contribute to a very small number of events each year, but these events typically involve a large number of customers (> 1000) per event). Individual incidents, such as the incident at North Troy, may have far-reaching consequences in terms of customer interruptions and return to service duration. This program will help improve reliability by proactively replacing or refurbishing units with incipient failure modes, and thus mitigating the risk of future unreliability.

Customer/Regulatory/Reputation - In addition to the benefits outlined in the Reliability category above, minimizing large-scale interruptions will help maintain favorable relationships with all external stakeholders.

Efficiency – The proposed program will improve The Company's performance knowledge of metal clad breakers through electro-acoustic testing, and subsequently allow The Company to prioritize replacements based on condition. Developing a long-range plan for managing the metal clad population will avoid significantly increasing maintenance and repair costs associated with aged and obsolete equipment.

METRICS TO TRACK BENEFIT(s):

Replacement of individual metal clad units will be tracked by count.

Improvements to SAIDI and SAIFI may be more difficult to quantify but will be analyzed using available IDS data.

Appendix 1: Metal Clad Condition and Performance Issues

A selection of 20 substations was analyzed with electro-acoustic techniques that detect partial discharges (PD), leading to identification of serious problems at Spring Street and Pine Bush substations, with subsequent failure avoidance through preventative maintenance. Main contact burrs at Johnson Road substation were repaired, and partial discharge from the R530 at Union Street substation noted, with follow up required. Intermittent partial discharge at Hopkins Road substation will be pursued with further electrical partial discharge detection. A failure at Glenwood substation in June 2009 was unexpected, the station had been the subject of roof repairs in 2007.

Overall the use of the electrical partial discharge survey has been very beneficial, with two probable failures avoided, and deteriorated equipment detected with action plans for mitigation developed. The Company plans to survey metalclad equipment on a regular basis to provide base line information on the assets, with an ad hoc approach to individual cases involving suspect assets.

Error! Reference source not found. identifies those metalclad stations which are of most concern with respect to performance and risk mitigation.

Table 3 Targeted metal Clad Installations

Station ID	Station Description	Watch
NY09-3140	Union Street Station 376	PD detected on R530; need to follow up to identify degradation mode
NY09-1730	Market Hill Station 324	Poor condition with possible PD
NY09-2230	North Troy Station 123	Replacement in progress
NY09-0930	Emmet Street Station 256	Poor condition with possible PD
NY09-1530	Johnson Road Station 352	PD related to main contact burrs detected and mitigated; follow up TEV required
NY08-5740	Springfield Station 167	Replacement in progress
NY08-0140	Ash Street	Initial design begun
NY09-0100	Altamont Station 283	Some rust with a bus failure in 2008
NY08-4350	Oneida Station 501	Replacement in progress based on condition
NY09-1320	Guy Park Station 239	Rusted throat connections and roof; due to be retired based on new 13.2 kV feeder

EXHIBIT 36

PROGRAM NAME:

Substation Circuit Breaker and Recloser

PROGRAM DESCRIPTION:

The Company has 4,106 circuit breakers (4,053 operating and 53 spares) on the distribution system, with an average age of 33 years. The method for managing substation breakers and reclosers consists of periodic maintenance and a "replace on condition" approach. This approach is being augmented by a replacement program targeting aged/unreliable breaker families, units in poor condition, and a formal spares policy as we first move to condition-based maintenance, then risk/criticality-based maintenance. The Company has specifically identified aged units for replacement because such units are difficult to repair, due to the lack of available spare parts (See Figure for equipment age profiles). Likewise, unreliable units have been identified for replacement because their replacement would reduce the number of customer interruptions.

Replacements under this strategy fall into two categories:

One-for-one replacements – Breakers in locations where replacement is expected to be straight-forward, with minimal additional work.

Part of larger Project – Many locations (indoor substations, metalclads, etc.) require additional work due to overall equipment condition, substation design, possible location retirement or complete location rebuilds. At these locations, any breaker replacements will become part of the larger project.

In either case, equipment is replaced based on condition. However, the schedule may be adjusted due to inclusion as part of a larger project.

The condition-based replacement program outlined in this strategy will be implemented over the next five years. This will permit the process of identifying and prioritizing the work to take place and allow for a smoother budgeting transition from the current to proposed state.

DRIVER(s):

The main drivers of the Distribution Substation Circuit Breaker and Recloser Strategy are:

- Equipment Condition (See Figure 1) - The current approach to breaker condition coding was developed based on engineering judgment and experience and was supported by discussion with local field staff. These condition codes were reviewed and updated in June of 2009.

Condition Code	Classification/Condition	Implication
1 Proactive	• Asset expected to operate as designed for more than 10 years	Appropriate maintenance performed; regular inspections performed
2 Proactive	• Some asset deterioration or known type/design issues • Obsolescence such that spares/replacement parts are not available • System may require a different capability at asset location	Asset likely to be replaced or refurbished in five to ten years; increased resources may be required to maintain/operate asset
3 Proactive	• Asset condition is such that there is an increased risk of failure • Test and assessment identifies definite ongoing deterioration	Asset likely to be replaced or refurbished in less than five years; increased resources may be required to maintain/operate asset
4 Reactive	• Asset has sudden and unexpected change in condition that is of immediate concern • This may be detected through routine diagnostics including inspections, annual testing, maintenance or following an event	Testing and assessment required to determine if asset may be returned to service or may be allowed to continue in service Following engineering analysis the asset will be either recoded to 1-3 or removed from the system

- Targeted Equipment Families – Targeted breaker families represent a subset of the entire population recommended for accelerated replacement due to age or poor reliability. Age-based replacements result from a lack of available spare parts and/or technological obsolescence. Reliability-based replacements result from poor historic reliability linked to a family of breakers. Presently, many of these replacement groupings are based on anecdotal evidence that has not been completely documented.

- Equipment Impact – Many substations have impact codes representing the relative importance of interruptions at the substation. These impact codes are derived in part from feeder load shedding priorities established by the System Control Centers and the local knowledge and expertise of the O&M services group. The impact codes will be used to prioritize breakers within each condition code grouping if necessary.

OTHER ALTERNATIVES CONSIDERED:

An alternative to the recommended strategy is a "fix on fail" approach. This method was not adopted due to:

- Expected increases in customer outages associated with poor condition breakers and unreliable breaker families.
- Reduced crew efficiency related to responding to more unplanned interruptions.
- Expected lack of control in investment management and supply chain.

CUSTOMER BENEFIT(s) OF PROGRAM:

<u>Safety and Environmental</u> - Several of the targeted breaker families present opportunities to reduce potential hazards associated with safety and the environment (e.g. oil leaks, presence of asbestos).

<u>Reliability</u> - Breaker failures and misoperations contribute a small number of events each year, but these events typically involve a large number of customers (> 1000) per event. This strategy will help improve reliability by proactively replacing or refurbishing units with poor reliability, or mitigate the risk of future unreliability. Breaker failures have resulted in an average of 20 substation events per year in the last 5 years (as reported in SIR) with an average of 12,000 customers interrupted and 1.5 million customer minutes interrupted. This equates to a SAIFI of 0.007, a SAIDI of 0.96 and a CAIDI of 130.6 minutes.

<u>Customer/Regulatory/Reputation</u> – In addition to those benefits outlined above, minimizing large-scale interruptions will help maintain favorable relationships with all external stakeholders.

<u>Efficiency</u> - Developing a long-range plan for managing the breaker population will avoid significant increases in maintenance and repair costs associated with aged and obsolete equipment.

METRICS TO TRACK BENEFIT(s):

The targets for this strategy are:

- Replace all breakers within the defined time-frame based on the condition codes
- Replace approximately 70 breakers per year to maintain a 60-year life expectancy target for this asset class due to the expected unavailability of spare parts and technological obsolescence.

Figure 1

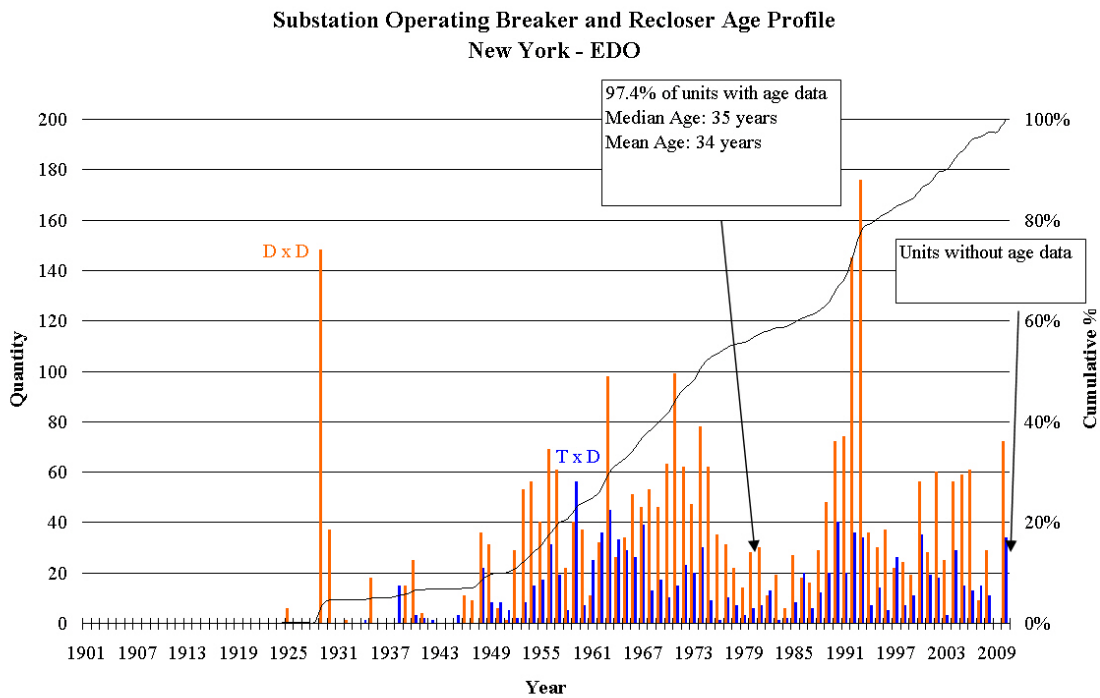


Figure 1 - Substation Breaker Age Profile

Exhibit 37
Projected Five Year Distribution Capital Plan - Programs

Spending Rationale	Program	FY10/11	FY 11/12	FY12/13	FY13/14	FY14/15	Total
Asset Condition	Blanket Total	5,750,000	5,750,000	5,150,000	4,600,000	4,000,000	25,250,000
	Distribution Line Transformer Total	125,000	0	0	0	0	125,000
	Duct Total	300,000	0	0	300,000	300,000	900,000
	Engineering Reliability Review Total	100,000	0	0	0	0	100,000
	Manhole/Vault Total	1,650,000	300,000	300,000	600,000	600,000	3,450,000
	Miscellaneous Underground Equipment Total	131,000	0	0	0	0	131,000
	Networks Total	2,100,000	2,100,000	2,000,000	2,250,000	2,500,000	10,950,000
	Open Wire Primary Total	750,000	0	0	0	1,500,000	2,250,000
	Overhead Secondary Total	330,000	0	0	330,000	330,000	990,000
	Planning Criteria Total	1,260,000	1,500,000	1,400,000	0	0	4,160,000
	Potted Porcelain Cutout Total	300,000	300,000	300,000	0	0	900,000
	Primary Underground Cable Total	3,400,000	4,500,000	3,000,000	4,500,000	6,000,000	21,400,000
	Substation Battery and Related Total	475,000	160,000	405,000	825,000	671,000	2,536,000
	Substation Circuit Breaker/Recloser Total	3,500,000	1,750,000	3,500,000	7,000,000	10,000,000	25,750,000
	Substation Circuit Switcher Total	900,000	0	0	0	0	900,000
	Substation Indoor Substation Total	8,585,000	13,950,000	17,700,000	17,700,000	17,700,000	75,635,000
	Substation Metal Clad Switchgear Total	1,250,000	4,875,000	5,025,000	3,000,000	3,000,000	17,150,000
	Substation Non-transformer Reactor Total	0	0	0	250,000	1,000,000	1,250,000
	Substation Overarching Total	700,000	100,000	100,000	500,000	1,150,000	2,550,000
	Substation Power Transformer Total	1,500,000	1,500,000	1,500,000	2,000,000	3,000,000	9,500,000
	Substation Relay/Protection Total	225,000	200,000	0	0	0	425,000
	Substation Voltage Regulator Total	450,000	0	0	0	0	450,000
	Subtransmission Line Overarching Total	100,000	0	0	0	0	100,000
	TBD Total	(800,000)	(1,500,000)	(1,250,000)	(2,690,000)	(5,531,000)	(11,771,000)
	Wood Pole Total	60,000	0	0	0	0	60,000
	(blank) Total	0	0	0	0	0	0
Asset Condition Total		**33,141,000**	**35,485,000**	**39,130,000**	**41,165,000**	**46,220,000**	**195,141,000**
Damage/Failure	Damage/Failure Total	19,485,000	20,604,000	21,363,000	22,110,000	22,970,000	106,532,000
	Major Storms - Dist Total	1,449,000	1,500,000	1,553,000	1,607,000	1,663,000	7,772,000
Damage/Failure Total		**20,934,000**	**22,104,000**	**22,916,000**	**23,717,000**	**24,633,000**	**114,304,000**
Non - Infrastructure	General Equipment - Dist Total	2,216,500	4,329,000	4,479,000	4,636,000	4,798,000	20,458,500
	Telecommunications Total	1,030,000	1,065,000	1,105,000	1,140,000	1,180,000	5,520,000
Non - Infrastructure Total		**3,246,500**	**5,394,000**	**5,584,000**	**5,776,000**	**5,978,000**	**25,978,500**
Statutory/Regulatory	3rd Party Attachments Total	265,000	280,000	290,000	300,000	310,000	1,445,000
	Inspection & Maintenance Total	17,440,000	28,960,000	25,075,000	22,057,000	20,044,000	113,576,000
	Land and Land Rights Total	1,920,000	2,076,000	2,245,000	2,428,000	2,626,000	11,295,000
	Meters - Dist Total	7,132,000	7,765,000	8,329,000	8,844,000	9,492,000	41,562,000
	New Business Total	45,983,000	49,052,000	51,638,000	54,002,000	56,696,000	257,371,000
	Outdoor Lighting - Capital Total	10,672,000	11,629,000	11,782,000	9,323,000	9,733,000	53,139,000
	Public Requirements Total	11,346,000	12,059,000	12,691,000	13,272,000	13,923,000	63,291,000
	Transformers & Related Equipment Total	26,830,000	29,933,000	32,536,000	34,539,000	37,242,000	161,080,000
Statutory/Regulatory Total		**121,588,000**	**141,754,000**	**144,586,000**	**144,765,000**	**150,066,000**	**702,759,000**
System Capacity & Performance	Blanket Total	6,631,000	7,161,000	7,754,000	8,284,000	8,900,000	38,730,000
	Capacitor Application Total	252,000	0	0	0	0	252,000
	Distribution Line Regulator Total	50,000	0	0	0	0	50,000
	Distribution Line Transformer Total	4,500,000	4,602,000	7,599,000	9,651,000	5,460,000	31,812,000
	Engineering Reliability Review Total	8,083,500	1,200,000	1,200,000	1,200,000	1,200,000	12,883,500
	Feeder Hardening Total	3,000,000	0	0	0	0	3,000,000
	Open Wire Primary Total	300,000	0	0	0	0	300,000
	Planning Criteria Total	29,881,000	21,500,500	22,541,000	21,412,000	24,493,000	119,827,500
	Pockets of Poor Performance Total	2,130,000	2,130,000	2,130,000	2,130,000	2,130,000	10,650,000
	Recloser Application Total	5,000,000	6,000,000	6,000,000	10,000,000	12,000,000	39,000,000
	Substation EMS/RTU Total	4,700,000	5,200,000	5,200,000	6,400,000	6,350,000	27,850,000
	Substation Overarching Total	1,108,000	3,719,500	110,000	0	0	4,937,500
	Substation Relay/Protection Total	105,000	250,000	250,000	500,000	500,000	1,605,000
	TBD Total	(800,000)	(1,500,000)		0	(1,930,000)	(4,230,000)
	URD Primary Total	150,000	0	0	0	0	150,000
System Capacity & Performance Total		**65,090,500**	**50,263,000**	**52,784,000**	**59,577,000**	**59,103,000**	**286,817,500**
Grand Total		**244,000,000**	**255,000,000**	**265,000,000**	**275,000,000**	**286,000,000**	**1,325,000,000**

Exhibit 38
Projected Five-Year Distribution Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
Asset Condition	Blanket	Cent NY-Dist-Asset Replace Blanket	CNC017	2,250,000	2,250,000	2,000,000	1,800,000	1,500,000	9,800,000	50
		East NY-Dist-Asset Replace Blanket	CNE017	1,000,000	1,000,000	900,000	800,000	700,000	4,400,000	50
		West NY-Dist-Asset Replace Blanket	CNW017	2,500,000	2,500,000	2,250,000	2,000,000	1,800,000	11,050,000	50
	Blanket Total			**5,750,000**	**5,750,000**	**5,150,000**	**4,600,000**	**4,000,000**	**25,250,000**	
	Distribution Line Transformer	Doghouse Replacement - Central Div	C26977	125,000	0	0	0	0	125,000	28
	Distribution Line Transformer Total			**125,000**	**0**	**0**	**0**	**0**	**125,000**	
	Duct	IE-NC Duct Replac Placeholder	C32091	100,000	0	0	100,000	100,000	300,000	34
		IE-NE_-Duct Replace Placeholder	C32093	100,000	0	0	100,000	100,000	300,000	34
		IE-NW_Duct replace Placeholder	C32095	100,000	0	0	100,000	100,000	300,000	34
	Duct Total			**300,000**	**0**	**0**	**300,000**	**300,000**	**900,000**	
	Engineering Reliability Review	Lape - Snyders Lake Tie	C26902	100,000	0	0	0	0	100,000	30
	Engineering Reliability Review Total			**100,000**	**0**	**0**	**0**	**0**	**100,000**	
	Manhole/Vault	IE- NC- MH Program Placeholder	C32101	100,000	100,000	100,000	200,000	200,000	700,000	34
		IE-NW-MH Program Placeholder	C32102	100,000	100,000	100,000	200,000	200,000	700,000	34
		IE-NE-MH-Program-Placeholder	C32103	100,000	100,000	100,000	200,000	200,000	700,000	34
		V-72 Howard St Replace Vault Roof	C32693	150,000	0	0	0	0	150,000	45
		V2325 Albany NY Roof Replacement	C33908	150,000	0	0	0	0	150,000	35
		V2326 Albany NY Roof Replacement	C33909	150,000	0	0	0	0	150,000	35
		V2327 Albany NY Roof Replacement	C33910	150,000	0	0	0	0	150,000	35
		V-6 Albany NY Roof Replacement	C33911	150,000	0	0	0	0	150,000	35
		V5825 Schenectady NY Roof Repl	C33912	150,000	0	0	0	0	150,000	35
		V573 Troy NY Roof Replacement	C33913	150,000	0	0	0	0	150,000	35
		V-500 Troy NY Roof Replacement	C33914	150,000	0	0	0	0	150,000	35
		V-198 Albany NY Roof Replacement	C33915	150,000	0	0	0	0	150,000	35
	Manhole/Vault Total			**1,650,000**	**300,000**	**300,000**	**600,000**	**600,000**	**3,450,000**	
	Miscellaneous Underground Equipment	LV Neutral Cable Replacement	C29214	131,000	0	0	0	0	131,000	27
	Miscellaneous Underground Equipment Total			**131,000**	**0**	**0**	**0**	**0**	**131,000**	
	Networks	Network Transformer Replacement	C29205	300,000	300,000	0	0	0	600,000	27
		Network Protector Replacement	C29206	300,000	300,000	0	0	0	600,000	27
		Albany Network Equipment	C33173	1,500,000	1,500,000	0	0	0	3,000,000	50
		Network	CNYNET	0	0	2,000,000	2,250,000	2,500,000	6,750,000	50
	Networks Total			**2,100,000**	**2,100,000**	**2,000,000**	**2,250,000**	**2,500,000**	**10,950,000**	
	Open Wire Primary	Schuylerville 12- Reconductor Rt 29	C10164	200,000	0	0	0	0	200,000	50
		Gilbert Mills 51 Rebuild due to QRS	C28590	550,000	0	0	0	0	550,000	31
		IE - NE Replace open wire primary	C31860	0	0	0	0	500,000	500,000	27
		IE - NC Replace open wire primary	C31861	0	0	0	0	500,000	500,000	27
		IE - NW Replace open wire primary	C31862	0	0	0	0	500,000	500,000	27
	Open Wire Primary Total			**750,000**	**0**	**0**	**0**	**1,500,000**	**2,250,000**	
	Overhead Secondary	Replace Open Wire Secondary-NY East	C27864	110,000	0	0	110,000	110,000	330,000	16
		Replace open wire secondary-NY Cent	C27884	110,000	0	0	110,000	110,000	330,000	16
		Replace open wire secondary-NY West	C27886	110,000	0	0	110,000	110,000	330,000	16
	Overhead Secondary Total			**330,000**	**0**	**0**	**330,000**	**330,000**	**990,000**	
	Planning Criteria	White Lake Station Upgrades	C08435	800,000	0	0	0	0	800,000	30
		Brunswick 52 New feeder getaway	C28688	0	0	0	0	0	0	27
		Alps - new dist sub - add feeder	C28788	100,000	1,500,000	1,400,000	0	0	3,000,000	36
		Alps - new dist sub - D Line work	C28790	0	0	0	0	0	0	27
		North Troy - Install Feeder Getaway	C31598	360,000	0	0	0	0	360,000	36
	Planning Criteria Total			**1,260,000**	**1,500,000**	**1,400,000**	**0**	**0**	**4,160,000**	
	Potted Porcelain Cutout	IE - NE Cutout Replacement	C10960	100,000	100,000	100,000	0	0	300,000	41
		IE - NC Cutout Replacement	C12967	100,000	100,000	100,000	0	0	300,000	41
		IE - NW Cutout Replacement	C12968	100,000	100,000	100,000	0	0	300,000	41
	Potted Porcelain Cutout Total			**300,000**	**300,000**	**300,000**	**0**	**0**	**900,000**	
	Primary Underground Cable	IE-NE Cable Replacements Placeholde	C11099	1,000,000	1,000,000	1,000,000	1,500,000	2,000,000	6,500,000	36
		IE-NW Cable Replacements Placeholde	C13282	1,000,000	2,000,000	1,000,000	1,500,000	2,000,000	7,500,000	36
		IE-NC Cable Replacements Placeholde	C13822	1,000,000	1,500,000	1,000,000	1,500,000	2,000,000	7,000,000	36
		Brook Road 36954 Getaway cable repl	C29113	400,000	0	0	0	0	400,000	30
	Primary Underground Cable Total			**3,400,000**	**4,500,000**	**3,000,000**	**4,500,000**	**6,000,000**	**21,400,000**	
	Substation Battery and Related	Battery Strategy FY09 CO36 DxT	C24240	125,000	125,000	125,000	125,000	125,000	625,000	35
		Batts/Charg--NY East	C32012	0	0	0	35,000	210,000	245,000	35
		Batts/Charg- NY Central	C32013	0	0	0	385,000	21,000	406,000	35
		Batts/Charg- NY West	C32014	350,000	35,000	280,000	280,000	315,000	1,260,000	35
	Substation Battery and Related Total			**475,000**	**160,000**	**405,000**	**825,000**	**671,000**	**2,536,000**	
	Substation Circuit Breaker/Recloser	NE ARP Breakers & Reclosers	C32252	1,000,000	500,000	1,000,000	2,000,000	3,000,000	7,500,000	35
		NC ARP Breakers & Reclosers	C32253	1,500,000	750,000	1,500,000	3,000,000	4,000,000	10,750,000	35
		NW ARP Breakers & Reclosers	C32261	1,000,000	500,000	1,000,000	2,000,000	3,000,000	7,500,000	35

Exhibit 38
Projected Five-Year Distribution Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
	Substation Circuit Breaker/Recloser Total			**3,500,000**	**1,750,000**	**3,500,000**	**7,000,000**	**10,000,000**	**25,750,000**	
	Substation Circuit Switcher	Circuit Switcher Strategy Co:36 DxT	C18850	900,000	0	0	0	0	900,000	34
	Substation Circuit Switcher Total			**900,000**	**0**	**0**	**0**	**0**	**900,000**	
	Substation Indoor Substation	Buffalo Indoor Sub. #29 Refurb.	C06722	1,450,000	0	0	0	0	1,450,000	37
		Buffalo Station 29 Rebuild - Fdrs	C06723	975,000	0	0	0	0	975,000	41
		Buffalo Indoor Sub. #23 Refurb.	C25639	650,000	0	0	0	0	650,000	50
		Buffalo Indoor Sub. #52 Refurb.	C25659	1,060,000	0	0	0	0	1,060,000	50
		Buffalo Indoor Sub. #43 Refurb.	C25660	950,000	0	0	0	0	950,000	50
		Buffalo Station 23 Rebuild - Fdrs	C27947	650,000	0	0	0	0	650,000	41
		Buffalo Station 43 Rebuild - Fdrs	C27948	650,000	0	0	0	0	650,000	41
		Buffalo Station 52 Rebuild - Fdrs	C27949	1,000,000	0	0	0	0	1,000,000	41
		Buffalo Station 27 Rebuild - Sta	C33473	300,000	3,500,000	1,500,000	0	0	5,300,000	50
		Buffalo Station 37 Rebuild - Sub	C33474	300,000	3,500,000	1,500,000	0	0	5,300,000	50
		Buffalo Station 59 Rebuild - Sub	C33475	300,000	3,500,000	1,500,000	0	0	5,300,000	50
		Buffalo Station 27 Rebuild - Line	C33476	100,000	750,000	0	0	0	850,000	50
		Buffalo Station 37 Rebuild - Line	C33477	100,000	750,000	0	0	0	850,000	50
		Buffalo Station 59 Rebuild - Line	C33478	100,000	750,000	0	0	0	850,000	50
		Buffalo Station 25 Rebuild - Line	CBUF25-2	0	100,000	500,000	0	0	600,000	41
		Buffalo Station 25 Rebuild - Sub	CBUF25-3	0	300,000	3,500,000	1,500,000	0	5,300,000	41
		Buffalo Station 30 Rebuild - Line	CBUF30-2	0	0	0	100,000	500,000	600,000	41
		Buffalo Station 30 Rebuild - Sub	CBUF30-3	0	0	0	300,000	3,500,000	3,800,000	41
		Buffalo Station 31 Rebuild - Line	CBUF31-2	0	0	100,000	500,000	0	600,000	41
		Buffalo Station 31 Rebuild - Sub	CBUF31-3	0	0	300,000	3,500,000	1,500,000	5,300,000	41
		Buffalo Station 32 Rebuild - Line	CBUF32-2	0	100,000	500,000	0	0	600,000	41
		Buffalo Station 32 Rebuild - Sub	CBUF32-3	0	300,000	3,500,000	1,500,000	0	5,300,000	41
		Buffalo Station 34 Rebuild - Line	CBUF34-2	0	0	100,000	500,000	0	600,000	41
		Buffalo Station 34 Rebuild - Sub	CBUF34-3	0	0	300,000	3,500,000	1,500,000	5,300,000	41
		Buffalo Station 35 Rebuild - Line	CBUF35-2	0	0	0	100,000	500,000	600,000	41
		Buffalo Station 35 Rebuild - Sub	CBUF35-3	0	0	0	300,000	3,500,000	3,800,000	41
		Buffalo Station 38 Rebuild - Line	CBUF38-2	0	0	0	0	100,000	100,000	41
		Buffalo Station 38 Rebuild - Sub	CBUF38-3	0	0	0	0	300,000	300,000	41
		Buffalo Station 41 Rebuild - Line	CBUF41-2	0	0	0	100,000	500,000	600,000	41
		Buffalo Station 41 Rebuild - Sub	CBUF41-3	0	0	0	300,000	3,500,000	3,800,000	41
		Buffalo Station 45 Rebuild - Line	CBUF45-2	0	0	0	0	100,000	100,000	41
		Buffalo Station 45 Rebuild - Sub	CBUF45-3	0	0	0	0	300,000	300,000	41
		Buffalo Station 51 Rebuild - Line	CBUF51-2	0	0	100,000	500,000	0	600,000	41
		Buffalo Station 51 Rebuild - Sub	CBUF51-3	0	0	300,000	3,500,000	1,500,000	5,300,000	41
		Buffalo Station 53 Rebuild - Line	CBUF53-2	0	100,000	500,000	0	0	600,000	41
		Buffalo Station 53 Rebuild - Sub	CBUF53-3	0	300,000	3,500,000	1,500,000	0	5,300,000	41
		Buffalo Station 68 Rebuild - Line	CBUF68-2	0	0	0	0	100,000	100,000	41
		Buffalo Station 68 Rebuild - Sub	CBUF68-3	0	0	0	0	300,000	300,000	41
	Substation Indoor Substation Total			**8,585,000**	**13,950,000**	**17,700,000**	**17,700,000**	**17,700,000**	**75,635,000**	
	Substation Metal Clad Switchgear	NY ARP MetalClad Equipment	C26054	250,000	1,875,000	2,225,000	3,000,000	3,000,000	10,350,000	35
		Altamont Sub Metalclad Replacement	C32296	850,000	1,500,000	1,400,000	0	0	3,750,000	35
		Market Hill Sub Metalclad Replacemt	C32298	150,000	1,500,000	1,400,000	0	0	3,050,000	35
	Substation Metal Clad Switchgear Total			**1,250,000**	**4,875,000**	**5,025,000**	**3,000,000**	**3,000,000**	**17,150,000**	
	Substation Non-transformer Reactor	Reactor Repl-NY Central	C31994	0	0	0	250,000	1,000,000	1,250,000	19
	Substation Non-transformer Reactor Total			**0**	**0**	**0**	**250,000**	**1,000,000**	**1,250,000**	
	Substation Overarching	NY Small Capital Items	C26760	100,000	100,000	100,000	100,000	0	400,000	50
		Mobile Readiness-NY East	C32003	0	0	0	0	750,000	750,000	34
		Mobile Readiness-NY Central	C32004	200,000	0	0	200,000	0	400,000	34
		Mobile Readiness-NY West	C32005	400,000	0	0	200,000	400,000	1,000,000	34
	Substation Overarching Total			**700,000**	**100,000**	**100,000**	**500,000**	**1,150,000**	**2,550,000**	
	Substation Power Transformer	IE - NY ARP Transformers	C25801	1,500,000	1,500,000	1,500,000	2,000,000	3,000,000	9,500,000	34
	Substation Power Transformer Total			**1,500,000**	**1,500,000**	**1,500,000**	**2,000,000**	**3,000,000**	**9,500,000**	
	Substation Relay/Protection	East NWP Relay Replacements	C28042	225,000	200,000	0	0	0	425,000	34
	Substation Relay/Protection Total			**225,000**	**200,000**	**0**	**0**	**0**	**425,000**	
	Substation Voltage Regulator	Ellicott Regulator Replacement	C32340	450,000	0	0	0	0	450,000	48
	Substation Voltage Regulator Total			**450,000**	**0**	**0**	**0**	**0**	**450,000**	
	Subtransmission Line Overarching	208 Line Refurbishment	C31633	10,000	0	0	0	0	10,000	40
		Lowville-Boonville #22 Dist Underbu	C32292	90,000	0	0	0	0	90,000	42
	Subtransmission Line Overarching Total			**100,000**	**0**	**0**	**0**	**0**	**100,000**	
	TBD	Reserve for Asset Replacement Unidentified Specifics & Sche	RESERVE 036_017 I	(500,000)	(1,000,000)	1,750,000	0	0	250,000	34
		Reserve for Asset Replacement Unidentified Specifics & Sche	RESERVE 036_017 S	(300,000)	(500,000)	(3,000,000)	(2,690,000)	(5,531,000)	(12,021,000)	34
	TBD Total			**(800,000)**	**(1,500,000)**	**(1,250,000)**	**(2,690,000)**	**(5,531,000)**	**(11,771,000)**	
	Wood Pole	NR-Distr-8043.08-CuNapth(soleowned)	C00194	60,000	0	0	0	0	60,000	50
	Wood Pole Total			**60,000**	**0**	**0**	**0**	**0**	**60,000**	

Exhibit 38
Projected Five-Year Distribution Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
	(blank)	Frontier 25 Hz Dist Sta Retirement	C32255	0	0	0	0	0	0	39
	(blank) Total			**0**	**0**	**0**	**0**	**0**	**0**	
Asset Condition Total				**33,141,000**	**35,485,000**	**39,130,000**	**41,165,000**	**46,220,000**	**195,141,000**	
Damage/Failure	Damage/Failure	DxT Substation Dmg/Fail Reserve C36	C18595	100,000	110,000	125,000	150,000	175,000	660,000	50
		Cent NY-Dist-Subs Blanket	CNC002	367,000	388,000	402,000	416,000	432,000	2,005,000	50
		Cent NY-Dist-Damage/Failure Blanket	CNC014	3,980,000	4,209,000	4,365,000	4,518,000	4,694,000	21,766,000	50
		East NY-Dist-Subs Blanket	CNE002	628,000	664,000	689,000	713,000	741,000	3,435,000	50
		East NY-Dist-Damage/Failure Blanket	CNE014	5,446,000	5,759,000	5,972,000	6,181,000	6,422,000	29,780,000	50
		West NY-Dist-Subs Blanket	CNW002	367,000	388,000	402,000	416,000	432,000	2,005,000	50
		West NY-Dist-Damage/Failure Blanket	CNW014	5,027,000	5,316,000	5,513,000	5,706,000	5,929,000	27,491,000	50
		Reserve for Damage/Failure Unidentified Specifics & Schedul	RESERVE 036_014 I	2,570,000	2,770,000	2,895,000	3,010,000	3,145,000	14,390,000	50
		Reserve for Damage/Failure Unidentified Specifics & Schedul	RESERVE 036_014 S	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	5,000,000	50
	Damage/Failure Total			**19,485,000**	**20,604,000**	**21,363,000**	**22,110,000**	**22,970,000**	**106,532,000**	
	Major Storms - Dist	Storm Damage - Dist - Western Div	C00056	483,000	500,000	517,700	535,600	554,400	2,590,700	50
		Storm Damage Distribution East Div.	C00328	483,000	500,000	517,700	535,700	554,300	2,590,700	50
		Storm Damage-Dist-Cent Div	C12965	483,000	500,000	517,600	535,700	554,300	2,590,600	50
	Major Storms - Dist Total			**1,449,000**	**1,500,000**	**1,553,000**	**1,607,000**	**1,663,000**	**7,772,000**	
Damage/Failure Total				**20,934,000**	**22,104,000**	**22,916,000**	**23,717,000**	**24,633,000**	**114,304,000**	
Statutory/Regulatory	3rd Party Attachments	Cent NY-Dist-3rd Party Attch Blankt	CNC022	95,000	100,000	102,500	105,000	110,000	512,500	50
		East NY-Dist-3rd Party Attch Blankt	CNE022	95,000	100,000	102,500	105,000	110,000	512,500	50
		West NY-Dist-3rd Party Attch Blankt	CNW022	75,000	80,000	85,000	90,000	90,000	420,000	50
	3rd Party Attachments Total			**265,000**	**280,000**	**290,000**	**300,000**	**310,000**	**1,445,000**	
	Inspection & Maintenance	FH - NE D-Line Work Found by Insp.	C26159	4,980,000	8,820,000	7,525,000	6,519,000	5,848,000	33,692,000	42
		FH - NC D-Line Work Found by Insp.	C26160	4,980,000	8,820,000	7,525,000	6,519,000	5,848,000	33,692,000	42
		FH - NW D-Line Work Found by Insp.	C26161	4,980,000	8,820,000	7,525,000	6,519,000	5,848,000	33,692,000	42
		FH - NE UG Work Found by Insp.	C26162	833,000	833,000	833,000	833,000	833,000	4,165,000	42
		NC - UG Work Found by Insp.	C26163	833,000	833,000	833,000	833,000	833,000	4,165,000	42
		NW - UG Work Found by Insp.	C26164	834,000	834,000	834,000	834,000	834,000	4,170,000	42
		FH - NE D-Line Work Found by Insp.	E07209	0	0	0	0	0	0	42
		FH - NC D-Line Work Found by Insp.	E07210	0	0	0	0	0	0	42
		FH - NW D-Line Work Found by Insp.	E07211	0	0	0	0	0	0	42
		FH - NE UG Work Found by Insp.	E07212	0	0	0	0	0	0	42
		FH - NC UG Work Found by Insp.	E07213	0	0	0	0	0	0	42
		FH - NW UG Work Found by Insp.	E07214	0	0	0	0	0	0	42
	Inspection & Maintenance Total			**17,440,000**	**28,960,000**	**25,075,000**	**22,057,000**	**20,044,000**	**113,576,000**	
	Land and Land Rights	Cent NY-Dist-Land/Rights Blanket	CNC009	1,325,000	1,433,000	1,550,000	1,676,000	1,813,000	7,797,000	50
		West NY-Dist-Land/Rights Blanket	CNW009	595,000	643,000	695,000	752,000	813,000	3,498,000	50
	Land and Land Rights Total			**1,920,000**	**2,076,000**	**2,245,000**	**2,428,000**	**2,626,000**	**11,295,000**	
	Meters - Dist	NiMo Meter Purchases	CN3604	4,982,000	5,522,000	5,970,000	6,378,000	6,911,000	29,763,000	50
		Cent NY-Dist-Meter Blanket	CNC004	670,000	699,000	735,000	768,000	804,000	3,676,000	50
		East NY-Dist-Meter Blanket	CNE004	763,000	796,000	837,000	875,000	916,000	4,187,000	50
		West NY-Dist-Meter Blanket	CNW004	717,000	748,000	787,000	823,000	861,000	3,936,000	50
	Meters - Dist Total			**7,132,000**	**7,765,000**	**8,329,000**	**8,844,000**	**9,492,000**	**41,562,000**	
	New Business	Primary service for Taconic Farms	C24233	500,000	0	0	0	0	500,000	50
		GML Tower	C29682	455,000	0	0	0	0	455,000	50
		Wal-Mart Sheridan Dr. - New Service	C30685	346,000	0	0	0	0	346,000	50
		Fairland URD	C31298	152,000	0	0	0	0	152,000	50
		Bolton 52 - Convert Valley Woods Rd	C31602	250,000	0	0	0	0	250,000	50
		Helderberg Meadows URD, Phase 1	C31612	360,000	0	0	0	0	360,000	50
		Bell's Pond Mobile Home URD	C32301	100,000	0	0	0	0	100,000	50
		Jenna's Forest URD	C32891	120,000	0	0	0	0	120,000	50
		Cent NY-Dist-New Bus-Resid Blanket	CNC010	10,286,000	11,037,000	11,639,000	12,190,000	12,829,000	57,981,000	50
		Cent NY-Dist-New Bus-Comm Blanket	CNC011	4,069,000	4,287,000	4,495,000	4,685,000	4,893,000	22,429,000	50
		East NY-Dist-New Bus-Resid Blanket	CNE010	9,772,000	10,486,000	11,058,000	11,582,000	12,189,000	55,087,000	50
		East NY-Dist-New Bus-Comm Blanket	CNE011	3,965,000	4,177,000	4,380,000	4,565,000	4,767,000	21,854,000	50
		West NY-Dist-New Bus-Resid Blanket	CNW010	7,715,000	8,279,000	8,731,000	9,145,000	9,624,000	43,494,000	50
		West NY-Dist-New Bus-Comm Blanket	CNW011	4,486,000	4,726,000	4,955,000	5,165,000	5,394,000	24,726,000	50
		Reserve for New Business Residential Unidentified Specifics &	RESERVE 036_010 I	2,408,000	3,640,000	3,840,000	4,020,000	4,230,000	18,138,000	50
		Reserve for New Business Commercial Unidentified Specifics	RESERVE 036_011 I	999,000	2,420,000	2,540,000	2,650,000	2,770,000	11,379,000	50
	New Business Total			**45,983,000**	**49,052,000**	**51,638,000**	**54,002,000**	**56,696,000**	**257,371,000**	
	Outdoor Lighting - Capital	Mercury Vapor Replacement	C26839	2,500,000	3,000,000	2,800,000	0	0	8,300,000	50
		Cent NY-Dist-St Light Blanket	CNC012	2,915,000	3,078,000	3,204,000	3,326,000	3,472,000	15,995,000	50
		East NY-Dist-St Light Blanket	CNE012	1,874,000	1,979,000	2,060,000	2,138,000	2,232,000	10,283,000	50
		West NY-Dist-St Light Blanket	CNW012	3,383,000	3,572,000	3,718,000	3,859,000	4,029,000	18,561,000	50
	Outdoor Lighting - Capital Total			**10,672,000**	**11,629,000**	**11,782,000**	**9,323,000**	**9,733,000**	**53,139,000**	
	Public Requirements	NYSDOT Ridge Rd Bridge	C15724	85,000	0	0	0	0	85,000	50
		DOT Queensbury Exit 18	C21511	1,600,000	0	0	0	0	1,600,000	50

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		NYS DOT Route 5	C22173	750,000	0	0	0	0	750,000	50
		Green Ave Road Widening	C22454	75,000	0	0	0	0	75,000	50
		Seneca Niagara Casino Relocation NF	C26639	50,000	0	0	0	0	50,000	50
		DOTR I-81 bridge reconstruction Syr	C29742	17,000	0	0	0	0	17,000	50
		DOT Albany Co., Johnston Rd.	C29825	100,000	0	0	0	0	100,000	50
		372 Battenkill Bridge - DOT	C30825	125,000	0	0	0	0	125,000	50
		DOT Glenville, Glenridge Rd.	C31258	340,000	0	0	0	0	340,000	50
		DOT Albany, Fuller Rd.	C31318	100,000	0	0	0	0	100,000	50
		DOT Amsterdam, Bridge St.	C31543	320,000	0	0	0	0	320,000	50
		DOT PIN3045.55 Rt104 Osw-Scriba	C31554	200,000	0	0	0	0	200,000	50
		DOT Erie Canal Lock E-13	C31811	540,000	0	0	0	0	540,000	50
		DOTR PIN7804.42 Rt68	C31868	150,000	0	0	0	0	150,000	50
		DOTR Latham, Rte.'s 2/7 Br/I-87	C32234	220,000	0	0	0	0	220,000	50
		DOT Saratoga, Rte. 9P Bridge	C32286	200,000	0	0	0	0	200,000	50
		NYSDOTR Rte. 28, Woodgate to McKeev	C32359	150,000	0	0	0	0	150,000	50
		DOT Schoharie, Rte.'s 30, 30A & 443	C32432	160,000	0	0	0	0	160,000	50
		DOT 4098.04- Rt 98 & 238 Attica	C32850	174,000	0	0	0	0	174,000	50
		DOT-Relocate facilities Maple Rd	C33253	12,000	0	0	0	0	12,000	50
		DOT CR106/Pine Grove Rd	C33351	44,000	0	0	0	0	44,000	50
		Cent NY-Dist-Public Require Blanket	CNC013	1,047,000	1,113,000	1,171,000	1,224,000	1,284,000	5,839,000	50
		East NY-Dist-Public Require Blanket	CNE013	1,885,000	2,003,000	2,108,000	2,204,000	2,313,000	10,513,000	50
		West NY-Dist-Public Require Blanket	CNW013	1,414,000	1,503,000	1,582,000	1,654,000	1,736,000	7,889,000	50
		Reserve for Public Requirements Unidentified Specifics & Sch	RESERVE 036_013 I	1,588,000	7,440,000	7,830,000	8,190,000	8,590,000	33,638,000	50
	Public Requirements Total			**11,346,000**	**12,059,000**	**12,691,000**	**13,272,000**	**13,923,000**	**63,291,000**	
	Transformers & Related Equipment	NiMo Transformer Purchases	CN3620	26,800,000	29,900,000	32,500,000	34,500,000	37,200,000	160,900,000	50
		Cent NY-Dist-Transf/Capac Blanket	CNC020	10,000	11,000	12,000	13,000	14,000	60,000	50
		East NY-Dist-Transf/Capac Blanket	CNE020	10,000	11,000	12,000	13,000	14,000	60,000	50
		West NY-Dist-Transf/Capac Blanket	CNW020	10,000	11,000	12,000	13,000	14,000	60,000	50
	Transformers & Related Equipment Total			**26,830,000**	**29,933,000**	**32,536,000**	**34,539,000**	**37,242,000**	**161,080,000**	
Statutory/Regulatory Total				**121,588,000**	**141,754,000**	**144,586,000**	**144,765,000**	**150,066,000**	**702,759,000**	
System Capacity & Performance	Blanket	Cent NY-Dist-Reliability Blanket	CNC015	1,739,000	1,878,000	2,034,000	2,173,000	2,334,000	10,158,000	50
		East NY-Dist-Reliability Blanket	CNE015	1,631,000	1,761,000	1,907,000	2,037,000	2,189,000	9,525,000	50
		West NY-Dist-Reliability Blanket	CNW015	3,261,000	3,522,000	3,813,000	4,074,000	4,377,000	19,047,000	50
	Blanket Total			**6,631,000**	**7,161,000**	**7,754,000**	**8,284,000**	**8,900,000**	**38,730,000**	
	Capacitor Application	Brockport Feeder Capacitors	C32510	252,000	0	0	0	0	252,000	36
	Capacitor Application Total			**252,000**	**0**	**0**	**0**	**0**	**252,000**	
	Distribution Line Regulator	Boyntonville 51 Regulators	C06679	50,000	0	0	0	0	50,000	50
	Distribution Line Regulator Total			**50,000**	**0**	**0**	**0**	**0**	**50,000**	
	Distribution Line Transformer	IE - NW Dist Transformer Upgrades	C10967	1,500,000	1,534,000	2,533,000	3,217,000	1,820,000	10,604,000	30
		IE - NC Dist Transformer Upgrades	C14846	1,500,000	1,534,000	2,533,000	3,217,000	1,820,000	10,604,000	30
		IE - NE Dist Transformer Upgrades	C15828	1,500,000	1,534,000	2,533,000	3,217,000	1,820,000	10,604,000	30
	Distribution Line Transformer Total			**4,500,000**	**4,602,000**	**7,599,000**	**9,651,000**	**5,460,000**	**31,812,000**	
	Engineering Reliability Review	Clinton 53 - Convert Ft Plain	C06698	0	0	0	0	0	0	23
		Chestertown 52 - Duell Hill Rd.	C07438	150,000	0	0	0	0	150,000	27
		NR-Gilpin Bay 95661-Fish Creek Pond	C15727	0	0	0	0	0	0	23
		NR-Gilpin Bay 95661-Hoel Pond	C15732	0	0	0	0	0	0	23
		IE - NE ERR and Fuse	C16117	400,000	400,000	400,000	400,000	400,000	2,000,000	30
		IE - NC ERR and Fuse	C16118	400,000	400,000	400,000	400,000	400,000	2,000,000	30
		IE - NW ERR and Fuse	C16119	400,000	400,000	400,000	400,000	400,000	2,000,000	30
		Caroga - G'ville 53 Feeder Tie	C19272	175,000	0	0	0	0	175,000	49
		NR-W.Adams87554-Church St	C22959	100,000	0	0	0	0	100,000	49
		Corinth 52 - Eastern Ave. Rebuild	C26876	900,000	0	0	0	0	900,000	36
		Guy Park Retirement Dist. Line	C26877	50,000	0	0	0	0	50,000	36
		NR-State St 95463-Judson St Rebuild	C26973	160,000	0	0	0	0	160,000	27
		Scofield 53 - Hadley/Harrisburg Rds	C28176	245,000	0	0	0	0	245,000	36
		Lehigh 66954 Teelin Rd Relocate	C28617	100,000	0	0	0	0	100,000	27
		Oneida 50153 Route 5	C28620	0	0	0	0	0	0	27
		Poland 62257 Steuben Rd	C28623	0	0	0	0	0	0	27
		F20871 rebuild ties F4768/F2569	C28625	162,000	0	0	0	0	162,000	27
		Delameter F9352 new ties w/18251,53	C28652	300,000	0	0	0	0	300,000	28
		F9753 Rebuild/Conv tie w/F21754	C28689	190,000	0	0	0	0	190,000	30
		F8566 Rebuild Various Sections	C28692	0	0	0	0	0	0	24
		Knapp Rd 22651 Feeder Tie	C28716	0	0	0	0	0	0	23
		N.Leroy 0455 - Mumford 5052 Fdr Tie	C28717	400,000	0	0	0	0	400,000	36
		E.Batavia 2855 - N.Leroy 0456 Tie	C28718	762,000	0	0	0	0	762,000	30
		Batavia 0155 - Knapp Rd 22651 Tie	C28719	532,000	0	0	0	0	532,000	36
		N.Eden 8251 Tie w/ F8861 & F8862	C28720	40,000	0	0	0	0	40,000	27

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Projected Five-Year Distribution Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		Delameter 9354 - 9353 Feeder Tie	C28721	0	0	0	0	0	0	27
		Delameter 9352 - Eden Ctr 8862 Tie	C28723	0	0	0	0	0	0	27
		Sweet Home F22457 tie with F2165	C28726	60,000	0	0	0	0	60,000	28
		Krumkill 51 Russell Rd convert	C28791	67,500	0	0	0	0	67,500	36
		Pinebush 37154 Prescott Woods	C28823	0	0	0	0	0	0	23
		NR-N Gouverneur 98352-Rt58 Transfer	C29101	300,000	0	0	0	0	300,000	27
		Battenkill 56 - Weibel 51 Tie	C29424	70,000	0	0	0	0	70,000	31
		Center St 54 - Rebuild Route 5S	C29426	0	0	0	0	0	0	18
		Chestertown 52 - Schroon River Rd	C29429	500,000	0	0	0	0	500,000	30
		Corinth 52 - Hudson River Crossing	C29430	200,000	0	0	0	0	200,000	35
		Farnan Rd 51 - Bluebird Road	C29431	0	0	0	0	0	0	21
		Inghams 51 - Route 108	C29433	0	0	0	0	0	0	23
		Middleburg 51 - Tie to Schoharie	C29434	120,000	0	0	0	0	120,000	30
		Northville 52 - EJ West 51 Tie	C29435	0	0	0	0	0	0	23
		Saratoga 4.16 kV Conversion	C29437	0	0	0	0	0	0	23
		Scofield Rd 53 - Tie to Corinth 51	C29438	800,000	0	0	0	0	800,000	30
		St Johnsville - Sanders Road	C29439	0	0	0	0	0	0	21
		Lehigh 66951 Tie with Turin 65355	C31772	500,000	0	0	0	0	500,000	50
	Engineering Reliability Review Total			**8,083,500**	**1,200,000**	**1,200,000**	**1,200,000**	**1,200,000**	**12,883,500**	
	Feeder Hardening	FH - NW Feeder Hardening	C10968	1,000,000	0	0	0	0	1,000,000	45
		FH - NC Feeder Hardening	C13145	1,000,000	0	0	0	0	1,000,000	45
		FH - NE Feeder Hardening	C13146	1,000,000	0	0	0	0	1,000,000	45
	Feeder Hardening Total			**3,000,000**	**0**	**0**	**0**	**0**	**3,000,000**	
	Open Wire Primary	Peterboro Reconductor Main St.	C28610	200,000	0	0	0	0	200,000	27
		Walesville Reconductor Utica St	C28616	100,000	0	0	0	0	100,000	27
	Open Wire Primary Total			**300,000**	**0**	**0**	**0**	**0**	**300,000**	
	Planning Criteria	St. Johnsville 51-Wagner/Wiltse Rds	C00376	200,000	0	0	0	0	200,000	14
		East Golah 51 - Second Bank	C06533	1,379,000	0	0	0	0	1,379,000	38
		East Golah -F5151E, F5151W & F5151C	C06765	786,000	0	0	0	0	786,000	38
		Whitaker 51 River Crossing	C06850	75,000	0	0	0	0	75,000	27
		Northville 52 - Convert N. Shore Rd	C07477	100,000	0	0	0	0	100,000	23
		Battenkill 34257 - Rebuild/convert	C07482	125,000	0	0	0	0	125,000	49
		EJ West 03841 - Convert to 13.2kV	C07798	100,000	0	0	0	0	100,000	50
		PS&I Activity - New York	C08153	100,000	105,000	110,000	115,000	120,000	550,000	36
		Delmar 440, Jun, Vooh 52 Conversion	C08606	600,000	0	0	0	0	600,000	27
		Rosa Road 55 - Overloaded Ratio bks	C12719	50,000	0	0	0	0	50,000	15
		Cuba 05 - Replace Transformer Bank	C15669	25,000	0	0	0	0	25,000	27
		Chautauqua 57 - Replace Xfmr	C15678	855,000	0	0	0	0	855,000	36
		Sheppard Rd. 29 - Second Bank	C15765	750,000	0	0	0	0	750,000	45
		Schroon 51 - Rebuild Route 74	C17962	0	0	0	0	0	0	23
		Port Henry 51 - Convert Westport	C18991	350,000	0	0	0	0	350,000	27
		Selkirk - Bethlehem Tie	C20691	40,000	0	0	0	0	40,000	50
		Attica12-Rebuild,Xfer F1263 to 0158	C26379	800,000	800,000	0	0	0	1,600,000	30
		Sycaway - Add M/C and 13.2kV Bus	C26418	2,066,000	0	0	0	0	2,066,000	35
		S. Newfane 71 - Replace Bank	C26481	25,000	0	0	0	0	25,000	48
		Buffalo Sta. 63 bank replacement	C26577	100,000	0	0	0	0	100,000	43
		Sycaway add 2nd Xfmr & 115 kV equip	C26819	1,929,000	0	0	0	0	1,929,000	40
		East Golah 51 - Secondary Breakers	C27062	700,000	0	0	0	0	700,000	38
		Raquette Lake 2.5 MVA	C27322	100,000	400,000	0	0	0	500,000	50
		NR- Morristown 2.5 MVA	C27323	142,000	0	0	0	0	142,000	34
		Swann Rd TB2 Replacement	C27449	2,200,000	0	0	0	0	2,200,000	34
		Sycaway-add new feeders	C28022	270,000	0	0	0	0	270,000	35
		Reynolds Rd - add new feeders	C28023	630,000	0	0	0	0	630,000	36
		LeMoyne Ave Rebild	C28545	400,000	68,000	0	0	0	468,000	48
		F5769/5763 Rebuild r/o Floradale	C28606	250,000	0	0	0	0	250,000	27
		Lehigh 66952 Tie With Colosse 32151	C28607	760,000	0	0	0	0	760,000	27
		McGraw 69 Low Voltage improvement	C28608	450,000	0	0	0	0	450,000	30
		Valley 59476 Rebuild Rasbach Rd	C28618	0	0	0	0	0	0	27
		Cavanaugh 61652 River Road	C28619	0	0	0	0	0	0	18
		Poland Convert Old State Rd	C28622	0	0	0	0	0	0	27
		Johnson 35251 - getaway replacement	C28765	90,000	0	0	0	0	90,000	30
		Inman Rd -Add M/C & 13.2kV Bus work	C28770	1,000,000	2,187,000	0	0	0	3,187,000	39
		Inman Rd - add new feeders	C28772	1,000,000	0	0	0	0	1,000,000	39
		Seminole 33904 - add feeder tie	C28780	100,000	0	0	0	0	100,000	30
		Riverside 28854 - replace getaway	C28781	155,000	0	0	0	0	155,000	36
		Chittenango Relief	C28816	300,000	0	0	0	0	300,000	34
		Park Load Relief	C28820	124,000	0	0	0	0	124,000	36

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Projected Five-Year Distribution Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
		Krumkill Voorheesville Tie	C28825	500,000	0	0	0	0	500,000	36
		Bartell 56 Orangeport	C28832	250,000	0	0	0	0	250,000	29
		Canajoharie D-Line Work	C28837	900,000	0	0	0	0	900,000	36
		Church St 04358 exten.	C28843	141,000	0	0	0	0	141,000	41
		Brook Rd 36957 Exten. Adams Road	C28844	473,000	0	0	0	0	473,000	36
		Fairdale Load Relief	C28847	300,000	0	0	0	0	300,000	29
		Mexico Load Relief	C28848	200,000	0	0	0	0	200,000	34
		Phoenix Load Relief	C28849	200,000	0	0	0	0	200,000	30
		Starr 53 Step Down	C28852	500,000	0	0	0	0	500,000	34
		Cortland 02 Relief	C28854	100,000	0	0	0	0	100,000	34
		E Syracsue 69 Conductor	C28869	60,000	0	0	0	0	60,000	27
		Station 21 - Split F2173	C28870	250,000	0	0	0	0	250,000	48
		Queensbury D-Line Work	C28874	0	0	0	0	0	0	36
		Frankhauser New Station - Line Work	C28929	600,000	600,000	0	0	0	1,200,000	41
		Frankhauser-115-13.2KV- Bus & Bkrs	C28931	300,000	2,000,000	0	0	0	2,300,000	41
		Batavia 01 - UG Cable Recond.	C29030	1,000,000	250,000	0	0	0	1,250,000	48
		Younsgtown 88 - Station Rebuild	C29049	750,000	0	0	0	0	750,000	36
		Station 79 - F7961 Relief	C29181	146,500	0	0	0	0	146,500	41
		Station 79 - F7962 Relief	C29182	190,000	0	0	0	0	190,000	41
		Station 214 - Install TB2	C29186	200,000	1,200,000	0	0	0	1,400,000	34
		Station 214 - New F21466	C29187	100,000	450,000	0	0	0	550,000	34
		Brook Road 55/57 - Daniels Rd	C29425	0	0	0	0	0	0	23
		Wilson Station 93 - Load Relief	C30124	0	750,000	750,000	0	0	1,500,000	48
		N Syracuse Sub Getaways	C30506	30,000	1,030,000	0	0	0	1,060,000	38
		DxT Study Budgetary Reserve - NIMO	C31550	100,000	100,000	100,000	0	0	300,000	49
		Rosa Rd 13756 - getaway replacement	C32070	0	0	0	26,250	0	26,250	27
		Amsterdam 32654 - extension	C32171	400,000	0	0	0	0	400,000	36
		NW Upgrade Panama Xfrm / Regs	C32306	0	525,000	0	0	0	525,000	36
		NW Langford 18061 Upgrade regs	C32310	0	0	0	0	0	0	23
		Fly 54 Fremont RR Cross	C32311	0	0	0	0	0	0	23
		NW N Collins Repl T1 Xfrm	C32313	0	0	0	0	0	0	24
		Farmersville Transformer Replacemen	C32339	525,000	1,575,000	0	0	0	2,100,000	45
		Sinclairville Transformer Replace	C32342	525,000	1,575,000	0	0	0	2,100,000	41
		Shelby 7657 Reconductoring	C32344	0	165,000	0	0	0	165,000	30
		Butts Rd. 7252 Extension	C32345	675,000	0	0	0	0	675,000	30
		W. Albion Transformer Addition	C32346	500,000	2,500,000	0	0	0	3,000,000	45
		NW 15467 336 SpC Med. Service #2	C32347	0	450,000	55,000	0	0	505,000	39
		NW Sta 154 - New 15465 Feeder	C32348	0	600,000	0	0	0	600,000	39
		NW - New 15465 Assoc DLine projects	C32349	0	525,000	0	0	0	525,000	39
		Albion 8064 Getaway Reconductoring	C32350	187,500	0	0	0	0	187,500	30
		NW Baker St Station Cap Bank	C32354	150,000	859,500	105,000	0	0	1,114,500	36
		NC Starr Rd Second Xfrm-13kv Switch	C32368	0	600,000	150,000	0	0	750,000	39
		NW-Batavia Sub Dist. Line Cap Banks	C32390	132,000	0	0	0	0	132,000	34
		Tonawanda 4.16 057 Recon UG Getaway	C32413	334,500	0	0	0	0	334,500	36
		S.Philadelphia 764 Transf. Upgrade	C32430	0	0	412,500	0	0	412,500	18
		Harris 54 Relief	C32446	0	0	0	0	0	0	27
		NW 15564 Fdr, Recond ug getaway	C32452	112,500	37,500	0	0	0	150,000	36
		NW Fdr 4671 Recond UG cable	C32453	187,500	37,500	0	0	0	225,000	41
		NW F3964 Extend ug, Xfer load	C32470	180,000	0	0	0	0	180,000	41
		Gilbert Mill Relief	C32494	508,500	0	0	0	0	508,500	36
		Paloma Second Transformer	C32495	0	0	0	405,000	855,000	1,260,000	39
		Harris Second Transformer	C32496	0	0	0	405,000	855,000	1,260,000	39
		Duguid Second Transformer	C32497	0	0	405,000	855,000	1,350,000	2,610,000	39
		NC Starr Rd. Second Xfrm	C32503	0	1,875,000	375,000	0	0	2,250,000	39
		Labrador 115-13.2kV	C32594	0	0	0	0	0	0	27
		Rathbun Labrador conversion	C32595	0	0	0	0	0	0	27
		Ogden Brook- install 13.2 kV s/gear	C32597	250,000	2,000,000	2,750,000	0	0	5,000,000	36
		Ogden Brook - Install new feeders	C32598	100,000	600,000	300,000	0	0	1,000,000	36
		Burgoyne - Inst. 2nd trans & s/gr	C32959	0	0	0	1,100,000	3,000,000	4,100,000	14
		Burgoyne - inst. cable getaways	C32972	0	0	0	5,000	25,000	30,000	14
		Ballston - Inst. second tranf & s/g	C33012	0	0	2,900,000	740,000	0	3,640,000	28
		Cent NY-Dist-Load Relief Blanket	CNC016	415,000	430,000	448,000	463,000	484,000	2,240,000	50
		East NY-Dist-Load Relief Blanket	CNE016	207,000	215,000	224,000	232,000	242,000	1,120,000	50
		West NY-Dist-Load Relief Blanket	CNW016	482,000	499,000	521,000	538,000	562,000	2,602,000	50
		Reserve for Load Relief Unidentified Specifics & Schedule Ch	RESERVE 036_016 I	(1,657,000)	(2,352,000)	1,251,000	1,527,750	5,000,000	3,769,750	34
		Reserve for Load Relief Unidentified Specifics & Schedule Ch	RESERVE 036_016 S	(750,000)	(1,156,000)	11,684,500	15,000,000	12,000,000	36,778,500	34
	Planning Criteria Total			**29,881,000**	**21,500,500**	**22,541,000**	**21,412,000**	**24,493,000**	**119,827,500**	

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Projected Five-Year Distribution Capital Investment Plan - Project Detail

Spending Rationale	Program	Project Name	Project Number	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15	Total	Risk Score
	Pockets of Poor Performance	Pockets of Poor Performance - NYW	C32576	710,000	710,000	710,000	710,000	710,000	3,550,000	41
		Pockets of Poor Performance - NYC	C32577	710,000	710,000	710,000	710,000	710,000	3,550,000	41
		Pockets of Poor Performance - NYE	C32578	710,000	710,000	710,000	710,000	710,000	3,550,000	41
	Pockets of Poor Performance Total			**2,130,000**	**2,130,000**	**2,130,000**	**2,130,000**	**2,130,000**	**10,650,000**	
	Recloser Application	IE - NE Recloser Installations	C13266	1,650,000	2,000,000	2,000,000	3,333,000	4,000,000	12,983,000	41
		IE - NC Recloser Installations	C13267	1,650,000	2,000,000	2,000,000	3,333,000	4,000,000	12,983,000	41
		IE - NW Recloser Installations	C13268	1,700,000	2,000,000	2,000,000	3,334,000	4,000,000	13,034,000	41
	Recloser Application Total			**5,000,000**	**6,000,000**	**6,000,000**	**10,000,000**	**12,000,000**	**39,000,000**	
	Substation EMS/RTU	REP - Dist Subs Without RTUs	C19851	250,000	250,000	250,000	250,000	0	1,000,000	30
		REP - Dist Subs EMS RTU DNP Plan	C20173	150,000	150,000	150,000	150,000	150,000	750,000	50
		NY RTU Program - DxT Subs	C22151	1,800,000	1,800,000	1,800,000	2,000,000	2,200,000	9,600,000	50
		EMS Placeholder	CNYEMS	2,500,000	3,000,000	3,000,000	4,000,000	4,000,000	16,500,000	34
	Substation EMS/RTU Total			**4,700,000**	**5,200,000**	**5,200,000**	**6,400,000**	**6,350,000**	**27,850,000**	
	Substation Overarching	N Syracuse Capacity Inc	C28831	670,000	2,320,000	110,000	0	0	3,100,000	48
		Bennett Rd. Sub Capacitor Install	C32367	438,000	1,399,500	0	0	0	1,837,500	36
	Substation Overarching Total			**1,108,000**	**3,719,500**	**110,000**	**0**	**0**	**4,937,500**	
	Substation Relay/Protection	Metallic Pilot Wire Protection Repl	C28449	105,000	250,000	250,000	500,000	500,000	1,605,000	34
	Substation Relay/Protection Total			**105,000**	**250,000**	**250,000**	**500,000**	**500,000**	**1,605,000**	
	TBD	Reserve for Reliability Unidentified Specifics & Schedule Cha	RESERVE 036_015 I	(500,000)	(1,000,000)		0	(1,930,000)	(3,430,000)	34
		Reserve for Reliability Unidentified Specifics & Schedule Cha	RESERVE 036_015 S	(300,000)	(500,000)		0	0	(800,000)	34
	TBD Total			**(800,000)**	**(1,500,000)**		**0**	**(1,930,000)**	**(4,230,000)**	
	URD Primary	Arbor Hill URD - Riverside 28858	C28814	150,000	0	0	0	0	150,000	23
		Stonehenge URD	C28826	0	0	0	0	0	0	23
	URD Primary Total			**150,000**	**0**	**0**	**0**	**0**	**150,000**	
System Capacity & Performance Total				**65,090,500**	**50,263,000**	**52,784,000**	**59,577,000**	**59,103,000**	**286,817,500**	
Non-Infrastructure	General Equipment - Dist	Cent NY-General-Genl Equip Blanket	CNC070	517,500	1,071,000	1,108,000	1,147,000	1,187,000	5,030,500	50
		East NY-Genl Equip Budgetary Reserv	CNE070	931,500	1,928,000	1,995,000	2,065,000	2,137,000	9,056,500	50
		West NY-General-Genl Equip Blanket	CNW070	517,500	1,071,000	1,108,000	1,147,000	1,187,000	5,030,500	50
		Reserve for General Equipment Specifics & Schedule Changes	RESERVE 036_070 I	250,000	259,000	268,000	277,000	287,000	1,341,000	34
	General Equipment - Dist Total			**2,216,500**	**4,329,000**	**4,479,000**	**4,636,000**	**4,798,000**	**20,458,500**	
	Telecommunications	Telecom and Radio Equipment	C04157	1,000,000	1,035,000	1,075,000	1,110,000	1,150,000	5,370,000	50
		Cent NY-Dist-Telecomm Blanket	CNC021	10,000	10,000	10,000	10,000	10,000	50,000	50
		East NY-Dist-Telecomm Blanket	CNE021	10,000	10,000	10,000	10,000	10,000	50,000	50
		West NY-Dist-Telecomm Blanket	CNW021	10,000	10,000	10,000	10,000	10,000	50,000	50
	Telecommunications Total			**1,030,000**	**1,065,000**	**1,105,000**	**1,140,000**	**1,180,000**	**5,520,000**	
Non-Infrastructure Total				**3,246,500**	**5,394,000**	**5,584,000**	**5,776,000**	**5,978,000**	**25,978,500**	
Grand Total				**244,000,000**	**255,000,000**	**265,000,000**	**275,000,000**	**286,000,000**	**1,325,000,000**	

EXHIBIT 39

PROGRAM NAME:

Distribution Line Transformer Strategy

PROGRAM DESCRIPTION:

To date, distribution line transformers have not posed a major concern with regard to the company's performance from, safety, environmental, reliability, or customer standpoints. To ensure this continued level of performance, a proactive load-based replacement program for these assets has been established. In addition, the condition of these assets is being managed as part of the Overhead and Underground Inspection and Maintenance Programs.

Transformer loading is reviewed annually via reports generated from the transformer loading information within the Geographical Information System (GIS). Transformers with calculated demands exceeding load limits specified in the applicable Construction Standard are investigated and any overloaded installations addressed. The number of installations reviewed annually is limited by the program budget.

The physical condition of distribution line transformers is evaluated on a five-year cycle as part of the Overhead and Underground Inspection and Maintenance Programs. Poor condition units are being replaced based on inspection results.

Heavily loaded units are to be systematically removed from the system over the next fifteen years. Unit replacements will increase year-on-year for the first five years of the program and stabilize for the remaining 10 years. Replacement levels may be adjusted based on changes to loading levels, the condition of the population and budget constraints.

DRIVER(s):

The main drivers of the Distribution Line Transformer Strategy are:

- Equipment Loading (See **Figure 1**) - Heavily-loaded transformers are not currently an increasing problem. However, it is important to manage equipment loading with proactive process based on annual reviews in order to maintain this situation.

- Asset Condition - Any condition-based replacements will be managed through the Inspection and Maintenance Program. Condition-based replacements represent much less than one percent of the inspected units.

- Customer Level Reliability - Load and condition-based transformer interruptions do not significantly impact overall system reliability but are significant at the customer level.

- Efficiency - The efficiency of the overall work process is improved through the programmatic identification and replacement of both heavily-loaded and poor condition transformers. Program-based replacements result in predictable current and future year budgets and support the proper management of the T&D work force during both normal and emergency operations. This efficiency flows through the entire asset life cycle from equipment procurement through investment recovery.

OTHER ALTERNATIVES CONSIDERED:

An alternative to the recommended strategy is a ‘fix on fail’ approach. This method was not adopted due to:

- Expected increase in customer outages associated with overloaded and poor condition transformers
- Reduced crew efficiency related to responding to more unplanned interruptions (especially during extreme heat/cold weather)
- Expected lack of control in investment management and supply chain

CUSTOMER BENEFIT(s) OF PROGRAM:

The main benefit of this strategy is that asset utilization will be maximized by maintaining units in service until such point that replacement is required as identified through recurring loading reviews or visual and operational inspection, recognizing that transformer life expectancy is predominantly affected by loading and environmental factors rather than age. Implementation of this strategy will ensure the sustainability of this asset class over time and maintain its relatively minor impact on overall system reliability.

Safety and Environmental - There is currently minimal impact related to safety and environmental drivers attributed to distribution line transformer failures. However, this strategy will minimize instances where dielectric fluid releases occur as a result of transformer failure due to overload or poor condition.

Reliability - The impact of distribution transformer failures on overall system reliability has historically been small. This strategy will ensure that the reliability performance of this asset class is maintained over time.

Customer – To date, there have been minimal customer impacts relating to distribution line transformer failures. This strategy will ensure that this low customer impact will be maintained over time.

Efficiency - The programmatic replacement of transformers based on loading and condition supports a predictable replacement rate and avoids unexpected changes to replacement in absence of loading and/or condition data. This predictable replacement rate better supports long term budgeting and the packaging of work for field crews.

METRICS TO TRACK BENEFIT(s):

The following performance targets are used to measure the successful implementation of this strategy:

- Completing the replacement of identified installations as part of each program year. Tracked via the REP Scorecard.
- Reduction in number of overloaded transformers as reported from the GIS over the 15 year program

Transformer Loading Profile

The total population of distribution transformers in New York consists of approximately 442,100 units in 392,000 installations.

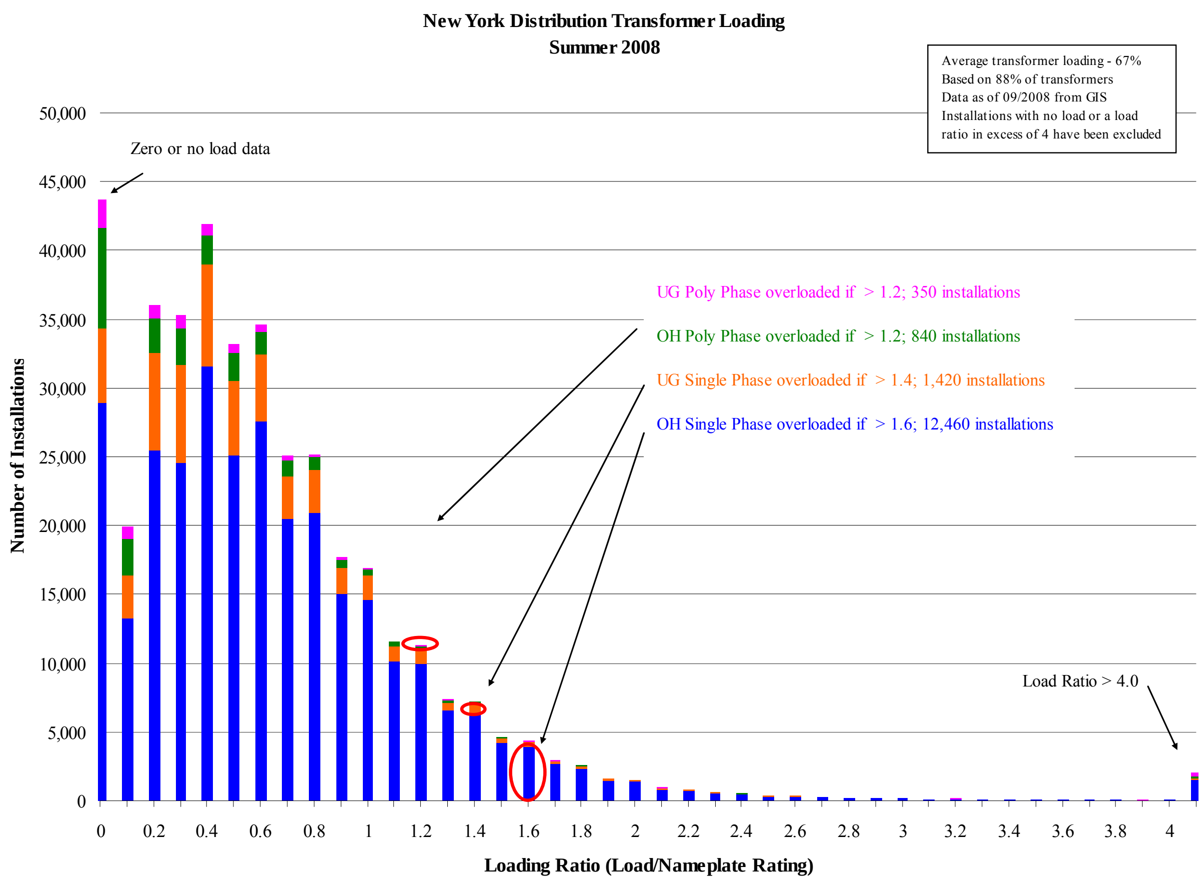

Figure 1 - Distribution Line Transformer Loading

EXHIBIT 40

PROGRAM NAME:

Feeder Hardening Strategy

PROGRAM DESCRIPTION:

The intent of this reliability focused strategy is to provide a method to identify feeders with characteristics indicating the potential for significant reliability performance improvements related to overhead deteriorated equipment and/or lightning interruptions. This is a reliability-focused strategy designed to meet both state regulatory targets.

After local review by Distribution Field Engineering, feeders identified as having these characteristics become part of the Feeder Hardening Program. Feeders in this program are surveyed for deteriorated equipment and non-standard grounding/bonding. All poles on which work is performed are brought up to current standards as part of the program.

Through October of 2009, approximately 200 feeders have been hardened representing more than 6,000 circuit miles of feeder hardening. The actual performance improvement on the 102 feeders previously completed through the end of FY2008 is shown in Figure 2 at the end of the report.

DRIVER(s):

The main drivers of the Feeder Hardening Strategy are:

- Reliability – Deteriorated equipment, lightning and animal related outages were steadily worsening prior to the program being implemented in FY2007.

- Meet State Regulatory Service Quality Targets – This program was designed to improve reliability in order to meet regulatory targets to eliminate financial penalties due to poor reliability performance.

OTHER ALTERNATIVES CONSIDERED:

An alternative to the recommended strategy was to create separate work lists for each driver (deteriorated equipment, lightning and animals) and address each one separately. This method was not adopted due to:

- Expected increase in design work associated with creating potentially three designs per work location
- Potential for multiple visits to the same pole to correct each outage type

- This approach may have resulted in slightly better targeting of reliability improvements but at the definite loss of work force efficiency

CUSTOMER BENEFIT(s) OF PROGRAM:

Safety and Environmental - As feeders are brought up to current standards, safety will be improved. This strategy has no direct environmental impact.

Reliability - This work is expected to reduce the five-year average SAIDI by 8 minutes on an IEEE basis by FY 2011. This improvement is based on a reduction in the number and magnitude of deteriorated equipment, lightning and animal related interruptions in upgraded sections.

Customer/Regulatory/Reputation - The overall goal is to meet state regulatory targets by 2008. Meeting our state regulatory service quality standards will eliminate financial penalties. Also, customers on the feeders in the program will experience a significant reliability improvement.

Efficiency - The programmatic, model-based approach used in this strategy ensures feeders selected for the Feeder Hardening Program present the best opportunity to meet the strategy's objectives. Additionally, combining the overhead deteriorated equipment, lightning and animal initiatives into one program maximizes the design, scheduling and crew time by addressing all programs with one visit to the pole.

METRICS TO TRACK BENEFIT(s):

The following performance targets are used to measure the successful implementation of this strategy:

- Meet state regulatory service quality targets by 2008.
- Complete all identified feeders and miles as part of each program year. Tracked via the REP Scorecard.

FY11 is the last year of the five-year program. Actual improvements on the feeders completed through FY2008 are shown below:

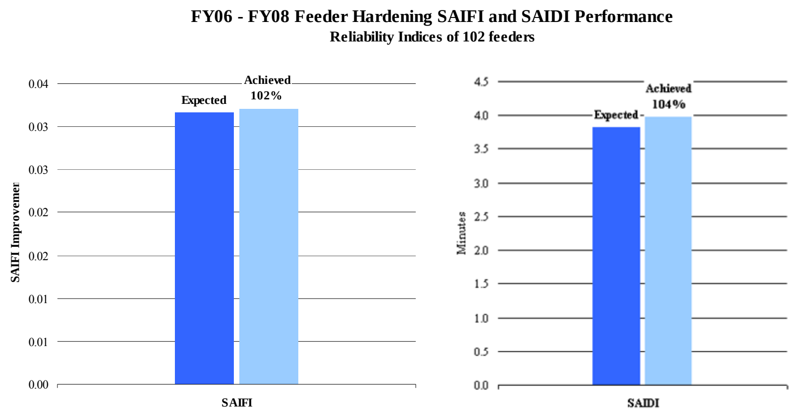

Figure 2 - Feeder Hardening Reliability Perform

EXHIBIT 41

PROGRAM NAME:

Pockets of Poor Performance

PROGRAM DESCRIPTION:

The intent of this strategy is to provide a method to identify subsections of feeders (typically at the line fuse level) experiencing measurably more frequent interruptions than the remainder of the feeder. Typically, these pockets of poor performance will not significantly impact the Company's service quality targets, but the interruptions are very significant to customers in the pocket.

There is no set list of equipment to inspect or replace as part of this strategy. Once these poor performance pocket locations have been identified, a reliability review of the area will be conducted by Network Asset Planning to determine the source(s) of the problem. The range of potential work could be as simple as solving a coordination problem to performing preventive maintenance (tree trimming, repairing equipment, grounding and bonding) to line reconductoring and/or stepdown conversion.

The model used to identify these pockets has been recently updated to work with the Interruption Disturbance System (IDS) to generate listings of interrupting devices experiencing multiple operations. This model is being reviewed and should be available for use as part of this program beginning in early 2010 in coordination with an updated version of the strategy.

As this is a new program, budgeting may be adjusted based on the results of the first year of the program.

DRIVER(s):

The main drivers of the Pockets of Poor Performance Strategy are:

- Customer Level Reliability – Reliability at the customer level is the main driver of this strategy. Identifying and correcting repeat device interruption locations will improve customer service.

- Minimize reliability "hot-spots" – This strategy will help identify future reliability "hot-spots" and support the timely correction of localized problems before they become larger issues.

OTHER ALTERNATIVES CONSIDERED:

An alternative is to continue the feeder based reliability initiatives. This alternative was not adopted due to a desire to look at reliability problems in a way which is more customer focused instead of feeder focused

CUSTOMER BENEFIT(s) OF PROGRAM:

Safety and Environmental - Although strategy is not focused on any specific safety or environmental benefits, as pockets of poor performance are addressed, any existing safety and/or environmental issues will also be corrected.

Reliability - This strategy addresses subsections of feeders experiencing measurably more frequent interruptions than the remainder of the feeder. The actual percentage improvement achieved will be driven by the budget available to fix these problems, but the impact will be significant for the customers in these pockets.

Customer - This strategy directly addresses subsections of distribution feeders that have reliability problems. Proactively reviewing these areas should improve the customer experience in these locations and minimize reliability "hot-spots" which result in a negative customer experience.

Efficiency –This strategy will reduce repeat visits to problem areas and provide opportunities to address issues identified in other strategies (Open Wire Primary, Line Reclosers, etc.).

METRICS TO TRACK BENEFIT(s):

The following performance targets are suggested (this strategy is scheduled to begin in FY2011) to measure the successful implementation of this strategy:

Reviewing a defined number of pockets per area as detailed on the appropriate management scorecard

EXHIBIT 42

PROGRAM NAME:

Addition of Remote Terminal Units (RTU's)for Substations

PROGRAM DESCRIPTION:

The addition of RTU's and associated infrastructure which subsequently communicate with an Energy Management System (EMS) for Substations and is proposed to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies. This program will also enable the distribution automation and smart grid strategies, and provide for a more sustainable distribution system.

DRIVER(s):

Currently over 150 substations require installations of RTU's in NY. Feeders equipped with automatic devices in NY are minimal in number. With the installation of RTU's, substation control and monitoring can be obtained through the EMS.

When used to monitor and control the distribution feeder breakers, EMS can provide a 15 to 20 percent reduction in average customer outage duration (CAIDI) when compared with a similar feeder that is not equipped with EMS facilities. This reduced outage time results primarily from the dispatcher receiving immediate notice of a switch operation and taking action before customers call to report the outage. EMS can also provide the dispatcher with fault location clues that can help reduce feeder patrol time. Substation EMS systems additionally provide system operators with immediate notification when an interruption occurs within a substation, so that service restoration activities can start immediately. Substation intelligent electronic devices can also provide an estimated fault location, which can cut feeder patrol time in half.

This program is designed to provide for a more sustainable distribution system by enabling the following advantages:

- Enable The Company personnel to operate a substation without having to travel to the substation
- Enable The Company to fully access and utilize the wealth of information contained in existing substations.
- Enable The Company personnel to access operational and non-operational data from substation without having to travel to the substation
- Allow quicker and more accurate diagnosis of faults to protect engineers and operations engineers, as well as to provide asset managers with data for smarter analysis tools.
- Improve asset management decisions based on hard statistical data and demand management profiles.

- Improve asset life cycle management and life extension
- Actual field measurements obtained from substation data benefit the design and engineering functions related to: system protection, power factor monitoring and control, phase balancing, circuit reconfiguration and load balancing, load forecasting, and outage trending.

Knowledge of the equipment condition, past performance, and historical loading and operations could be used to determine the remaining life of the equipment, future maintenance requirements, and ultimately the economic decision making criteria for retirement and life extension alternatives. The ability to perform these decisions more accurately is becoming increasingly important as the equipment population increases in age.

OTHER ALTERNATIVES CONSIDERED:

The other alternative is to not install RTU's in substations except where required, which is not recommended because the Company would forego the benefits discussed above.

CUSTOMER BENEFIT(s) OF PROGRAM:

This program provides the means to leverage substation data that provides operational intelligence and significantly reduces response time to abnormal conditions through real time monitoring and control. This program enables the implementation of the distribution automation, sub-transmission automation, and future smart grid strategies,

This program will also improve service to customers. EMS systems, when used to monitor and control the distribution feeder breakers and associated feeder equipment, can provide a 15 to 20 percent reduction in CAIDI, when compared with a similar feeder that is not equipped with SCADA facilities.

METRICS TO TRACK BENEFIT(s):

The following performance targets are used to measure the successful implementation of this strategy:

- Completing the installation of RTU's at identified substations and selected distribution and sub-transmission circuits as part of each program year, tracked via the budget process.
- Reduce CAIDI by 10% on those feeders and substations with an RTU and EMS installed.

EXHIBIT 43

PROGRAM NAME:

Recloser Application

PROGRAM DESCRIPTION:

The recloser application strategy is a reliability-focused strategy designed to support the Company's reliability performance through the installation of line reclosers on overhead distribution lines.

Line reclosers are primarily installed on 15 kV class distribution feeders with overhead exposure.

DRIVER(s):

Line reclosers are needed to isolate permanent faults on the distribution system and minimize the scope of the interruption by protecting the feeder breaker. Ideally, reclosers are installed at locations which limit the size of the interruption to the fewest number of customers possible and/or reduce the mainline exposure on the feeder breaker. Reclosers should be installed at natural breakpoints in the distribution primary: e.g., bifurcations, long three phase taps, etc.

Pursuant to this strategy the Company plans to install at least one recloser on every 15 kV class radial feeder with significant overhead three phase exposure (more than 10 miles) with a three year average distribution line SAIDI performance (Regional IEEE 1366 basis) greater than the internal The Company SAIDI goal (estimated at 96 minutes, based on 120 minute goal less 20%). Additionally any circuit identified as a desirable candidate from the Recloser Model would be eligible or any location having a $/Delta CMI equal to or less than $1.50. Candidates will be considered for inclusion in the budget based on their $/Delta CMI value, with the more economic reclosers being included.

OTHER ALTERNATIVES CONSIDERED:

The only other option is to do nothing. The Company rejected this option because it would maximize the size of interruptions by spreading them to a larger number of customers and/or increase the mainline exposure on the feeder breaker. It would also have a very negative impact on the level of service provided to our customers and to the overall reliability of the system.

CUSTOMER BENEFIT(s) OF PROGRAM:

The principal benefits of the Recloser Application Strategy are reliability and customer related.

Reliability

This program will improve overall system reliability by reducing both outage durations and frequencies.

Customer/Regulatory/Reputation

This strategy will result in an improvement in service quality for all customers. The additional reclosers will limit the size and duration of future distribution interruptions. This strategy has no direct regulatory impact but the projected reliability improvements will aid in meeting future service quality targets.

METRICS TO TRACK BENEFIT(s):

The installation benefits of the recloser program will be tracked through interruptions CI and CMI

EXHIBIT 44

PROGRAM NAME:

Engineering Reliability Review Program

PROGRAM DESCRIPTION:

The Engineering Reliability Review (ERR) program identifies where opportunities exist to improve feeder (circuit) reliability as part of The Company's Reliability Enhancement Initiative and as mandated by the New York PSC.

A strategy for implementing Engineering Reliability Reviews (ERRs) is under development, linking through to feeder performance and reliability. As noted in last year's (2009) capital investment plan filing CIP 2009, there is a documented review procedure: the Distribution Asset Management Guideline 012 (DAM-012).

The Regulatory Compliance group is responsible for generating the list of Worst Performing Feeders during the preparation of the Electric Service Reliability Report filed annually in accordance with Case 90-E-1119. The list of feeders includes outages associated with supply issues (transmission or substation) and excludes major storms. From that list, feeders are selected for an ERR. The ERRs are generated by the Distribution Field Engineering (Network Asset Planning group). Each review includes:

- Review of historical reliability data. One year and three year for current issues and trends.
- Review of recently completed and/or future planned work which is expected to impact reliability.
- Review the need for the installation of radial and/or loop scheme reclosers.
- Review for additional line fuses to improve the sectionalization of the feeder.
- Comprehensive review of the coordination of protective devices to ensure proper operation.
- Review for equipment in poor condition.
- Review of heavily loaded equipment.
- Review for other feeder improvements such as fault indicators, feeder ties, capacitor banks, load balancing, additional switches to reconductoring (overhead and/or underground).

The Engineering Reliability Review process has been in place since FY2006/2007 pursuant to which 180 feeders have been reviewed. To date, this program is responsible for the majority of the more than 330 recloser installations and thousands of side tap fuses associated with the Reliability Enhancement Program over the past two years. A number of feeder tie and conductor replacement projects have also been initiated but are not yet completed.

DRIVER(s):

The Company has a regulatory obligation to report on the worst 5% performing circuits in New York and provide recommendations to improve their reliability. The ERRs are the analyses and recommendations that are made to improve the reliability on the worst performing circuits.

OTHER ALTERNATIVES CONSIDERED:

There was no alternative to the ERRs considered due to the regulatory requirement to report on recommendations relating to NY's worst performing circuits. The Engineering Reliability Reviews aim to solve the problems associated with these feeders. Doing nothing would lead to continued poor performance.

CUSTOMER BENEFIT(s) OF PROGRAM:

The ERR program will benefit the customer's reliability by focusing our attention on the worst performing circuits. There is also the risk of incurring a financial penalty by not addressing the circuits that are on the worst performing circuit list.

METRICS TO TRACK BENEFIT(s):

The key method to track the benefits of the ERR program will be provided by the annual worst performing feeder list. The list will provide the overall number of interruptions, customer hours of interruptions (CHI), system average interruption frequency index (SAIFI), and system average interruption duration index (SAIDI) of a circuit for the fiscal year. One can then see year to year improvements of a circuit based on the ERRs recommendations (minus other work performed on the circuit).

EXHIBIT 45

PROGRAM NAME:

Open Wire Primary Strategy

PROGRAM DESCRIPTION:

The intent of this strategy is to replace all "small" (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability.

Approximately 4,800 circuit miles (14%) of the overhead circuit mileage falls into the category of small wire. The three-phase portion of the small wire circuit mileage is 510 miles (< 2% of total, 11% of small wire). The majority of this small wire population is #6 and #4 copper/copperweld conductor.

Three general strategies have been developed to address this small wire population:

1.) Replace three phase installations on a feeder basis
2.) Replace both three phase and non-three phase small wire installations in areas identified as pockets of poor performance
3.) Replace as part of all future overhead distribution projects

Three phase areas are the main focus due to the expected larger contribution to the overall performance of the feeder from a reliability, loss, voltage and loading perspective.

Presently this approach is not fully implemented, however many primary conductor replacement projects are active related to the Enhanced Infrastructure portion of the Reliability Enhancement Program. These projects are targeting voltage and load related issues that are predominantly associated with small conductors.

An improved method to locate appropriate candidates is needed to better support this strategy. Currently Engineering Reliability Reviews, Pockets of Poor Performance, Problem Identification Worksheets and the Inspection and Maintenance Program are the sources by which the Company has identified potential projects.

DRIVER(s):

The main drivers of the Open Wire Primary Strategy are:

- Reliability – The small wire asset group consists mainly of older installations (> 50 years old). Due to the harsh operating environment and service length most conductors will have lost some tensile strength due to loading conditions and splicing activities, which make the conductor more likely to break during an interruption involving physical contact with the conductor (e.g. trees). This is especially significant during storm events due to additional wind/snow and ice loading.

- System Losses, Voltage Drop and Loading – Small conductors have increased contributions to system losses, voltage drop and loading. Replacement of small primary will improve system performance in these areas.

- Asset Condition - Any condition-based replacements will be managed through the Inspection and Maintenance Program.

OTHER ALTERNATIVES CONSIDERED:

An alternative to the recommended strategy is a 'fix on fail' approach. This method was not adopted due to:

- Expected increase in customer interruptions due to conductor deterioration
- Continued issues related to losses, voltage and loading

CUSTOMER BENEFIT(s) OF PROGRAM:

The main benefit of this strategy is that system performance will be improved by replacing "small" wire. The principle areas that will benefit from this replacement are reliability, losses, voltage, and loading. Additionally, this replacement will remove a group of assets from the system that are in poor condition based on inspection.

METRICS TO TRACK BENEFIT(s):

The following performance targets are used to measure the successful implementation of this strategy:

- Completing the replacement of identified installations as part of each program year, tracked via the budget process.
- Completion of conductor related codes within Computapole with prescribed time frames

EXHIBIT 46

PROGRAM NAME:

Manhole and vault asset replacement program.

PROGRAM DESCRIPTION:

Manholes and vaults are inspected on a five year cycle and prioritized based on The Company's Electric Operating Procedures (EOP UG006-UG Inspection and Maintenance). The inspection priority system (1-4) will identify and provide for timely condition-based replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle. Inspections are also made whenever work is done inside a manhole or vault. When defects are discovered during an inspection, they are to be cataloged in existing systems according to current procedures and identified for repair.

DRIVER(s):

Per New York regulatory mandate, manholes and vaults are examined on a five year cycle. The manhole and vault asset replacement program will be incorporated into the Inspection & Maintenance program. Please refer to the Inspection & Maintenance Program justification document for further details.

OTHER ALTERNATIVES CONSIDERED:

One alternative that was considered but not chosen was to fix on fail. This method was not chosen because it does not result in preventing and locating potential failures that could pose a danger to employees and the public.

Another alternative that was considered but not chosen was to replace assets via age data. This alternative was not chosen due to its inconsistent nature and the lack of age data along with the fact that age data does not provide a reliable guide to the condition of individual assets.

CUSTOMER BENEFIT(s) OF PROGRAM:

In general manholes and vaults are in sound condition. The typical means of degradation is weakening of the roof structures. Potential harm to employees and the public exists from weakening roof structures. This program will minimize such potential harm.

Only rarely do structural problems directly cause reliability problems. On such occasions, however, structural problems can delay service restoration after an interruption has occurred. By reducing potential structural problems, such delays will be further avoided.

METRICS TO TRACK BENEFIT(s):

The inspection priority system (1-4) will identify and provide for timely condition-based replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle. Please refer to the Inspection & Maintenance Program Justification Document for further details.

EXHIBIT 47

PROGRAM NAME:

Underground Network Program

PROGRAM DESCRIPTION:

The underground network asset replacement program targets the maintenance, monitoring and installation/replacement of: limiters, transformers, protectors, secondary cables and miscellaneous underground network assets.

DRIVER(s):

The underground network systems are an aging infrastructure that requires monitoring, maintenance and replacements to maintain reliability. Though underground networks are a reliable system, when incidents do occur the restoration can end up being very lengthy and costly.

There is a The Company (internal) environmental requirement to shut down sump pumps in network vaults that do not contain a filter. The requirement is due to the potential pumping of contaminated water from vaults into public accessible areas. Some residual damage is starting to show up as rusting equipment, switching problems, and transformer failures. This program will balance meeting the environmental requirement while maintaining the affected assets.

Underground networks are prioritized for work performed under this program by load served and the number of customers on the network system. The Company has initiated a number of studies to analyze the ability of the secondary network cables to clear during fault conditions as a result of previous underground network incidences. Load flow studies have also been completed on the Buffalo, Syracuse Ash St, Syracuse Temple St, Watertown and Troy networks. All networks will have a load flow study performed. Studies are planned for Networks in Utica, Albany with the remaining networks to follow.

OTHER ALTERNATIVES CONSIDERED:

One alternative that was considered but not chosen was to fix on fail. This method was not chosen because it would not prevent potential failures that could pose an environmental and safety concern to employees and the public.

Another alternative that was considered but not chosen was to make recommendations on network asset replacements and upgrades solely based on inspection results. This alternative was also rejected. Although inspections aid in obtaining information on the condition of the assets it does not provide a complete set of information on their current condition; some failure modes and deterioration mechanisms are not detectable through visual inspection, thus posing an environmental and safety concern to employees and the public.

CUSTOMER BENEFIT(s) OF PROGRAM:

The Companys underground network systems are reliable and in generally sound condition. However, when underground network failures do occur they typically require lengthy restoration efforts due to location and feasibility of repairing/replacing equipment and with unexpected civil work. There have also been underground network failures which have involved equipment that has caught on fire and leaked oil. These types of failures can pose an environmental and safety concern for customers and employees. Also, simple underground network failures (which are what have historically occurred) do have the potential to escalate into significant failures that can impact all customers that are served on a network. By continuing with the underground network program, The Company is taking a proactive approach to maintaining and monitoring the underground network system and thus avoiding such significant outages, and the safety and environmental consequences thereof.

METRICS TO TRACK BENEFIT(s):

The Underground Network Strategy will track the condition of each network based on reliability results, inspection results and the feedback from the subject matter experts. The reliability metrics of SAIFI and SAIDI will be also used to track the benefits of the underground network program.

EXHIBIT 48

PROGRAM NAME:

Indoor Substation Rebuild and Refurbishment

PROGRAM DESCRIPTION:

This purpose of this program is to review the rebuild options for 22 indoor substations located in Buffalo and six indoor substations located in Niagara Falls. This refurbishment plan is required to remove safety and equipment failure risks based on asset conditions detailed in the Report on the condition of Physical Elements on Transmission and Distribution Systems filed on October 1, 2009 in Case No. 06-M-0878.

The indoor substations in Buffalo and Niagara Falls were built in the early 1930's and are therefore over 70 years old. In addition to age, the stations have inherent safety risks due to design and equipment condition. Twenty two "Buffalo Style" indoor 23kV-4.16kV substations remain in service in the Buffalo.

DRIVER(s):

Safety/Environmental

Key drivers for the Buffalo Station rebuilds are a number of personnel safety issues which are highlighted below:

- 23 kV Condit oil switches were misapplied as circuit breakers at the primaries of the transformers. These switches do not have the interrupting capacity for current system fault conditions, and require the operator to be physically at the switch for operation. The switches do not have a remote operation capability. As an example, the failure of a Condit switch during manual operation caused serious burns to a Travelling Operator and severe damage to several bays in the station due to the subsequent fire.

- Operation of the 4.16 kV oil circuit breakers requires the operator to be standing at the breaker. In addition, these breakers have no provision for proper safety grounding for maintenance, and require personnel to crawl up under the breaker's support structure in order to perform activities such as operating mechanism maintenance and tank removal.

- The protective relay scheme is of obsolete design, and does not provide adequate protection for some types of faults. For example, only two of the three phases have overcurrent relays at 23kV. In the event of a transformer secondary fault, such as in the regulators, the relays may not always detect the fault, allowing it to escalate to a catastrophic failure of the regulator or other equipment.

- In the event of a severe fault, the primary relays have a blocking function that prevents them from opening the (underrated) primary breaker, leaving the fault to be cleared by relays at the source terminal of the 23kV feeder. This can also lead to greater equipment damage and personnel hazards.

System Capacity and Performance

In addition to safety, the station rebuilds have been driven by issues of station loading and transformer capacity. This has resulted in replacing the existing 2500kVA transformers with 3750kVA units. Note, however, that the 23kV cable system feeding the stations has not been upgraded to support this potential increase in total load. Loading and capacity issues include:

- The present loads on the stations have produced problems when failure of one 23kV feeder into a station took place while another feeder was out of service for maintenance. The result was total shut-down of the station due to the overloading of the remaining transformers, followed by rolling blackouts until the feeders could be returned to operation.

- Poor ventilation in transformer bays has led to transformer overheating and possible accelerated aging of insulation as transformer loads have increased.

Asset Condition

Asset condition linked to aging equipment is another driving factor for the Buffalo Station rebuilds.

The original bays (sections 1-3) of the Buffalo stations date from 1929 to 1931. Some stations had a fourth bay added in the 1940s and 50s. This places equipment ages from 50 to 75 years, which is beyond their designed service life. Although much equipment is still operating at that age, the probability of its failure increases with time. In addition, obsolete equipment often does not meet current requirements (*i.e.* speed of operation) for fault interrupting capability, operating interfaces, and personnel safety.

The existing 4.16 kV feeder protection which is a meter-style enclosure, does not allow interchange of the relays for different timing characteristics. This has limited the ability to connect some customer loads to the feeders and achieve proper coordination of protective devices. Some feeders have been modified with newer, switchboard-case relays, but with nine to twelve feeders per station, the modification becomes costly to perform universally.

Wear of the 4.16 kV circuit breakers' operating mechanisms causes mis-operations. The failure of a breaker to trip for a fault can expose other aging and often underrated equipment to stresses above its capabilities, as well as posing a safety hazard.

OTHER ALTERNATIVES CONSIDERED:

An alternative to the recommended strategy is a 'fix on fail' approach. This method was not adopted due to:

- failure to address safety issues
- potential inefficiency associated with one-for-one asset replacement
- expected increase in customer outages associated with poor condition and increasingly unreliable substation equipment.

CUSTOMER BENEFIT(s) OF PROGRAM:

Safety and Environmental - This strategy will address safety concerns associated with these indoor substations, as discussed above.

Reliability - This work is expected to reduce the SAIDI. This improvement is based on a reduction in the mis-operations and addition of automation for control and monitoring. Customers served from these substations will benefit from substations refurbished with modern equipment and technology to address asset conditions that will improve the reliability of these substations in future years.

Customer/Regulatory/Reputation - In addition to those benefits outlined in the safety and environmental and reliability sections, minimizing large-scale interruptions will help maintain favorable relationships with all external stakeholders.

Efficiency - Developing a long-range plan for managing the indoor substation population will avoid significantly increasing maintenance and repair costs associated with aged and obsolete equipment.

METRICS TO TRACK BENEFIT(s):

The following performance targets are used to measure the successful implementation of this strategy:

Completion of work on all identified substations and key components, such as feeders, as part of each program year.

EXHIBIT 49

PROGRAM NAME:

Distribution Substation Transformer

PROGRAM DESCRIPTION:

The Distribution Substation Transformer program will allow The Company to confidently rank its substation transformers in terms of health and risk and to identify the transformers most critical to the system so that all substation transformers may be assigned a proper priority for asset replacement.

This program supports achieving improved reliability and meeting service quality standards in all states in which The Company operates.

DRIVER(s):

The main drivers of the Distribution Substation Transformer Strategy are:

- maintain reliability based on condition assessment
- improve reliability of network
- increase safety of the public and/or employees
- develop a contingency plan for units at risk of failure
- support state/company environmental goals
- meet regulatory requirements
- improve of customer relations and reputation

Maintaining reliability based on condition assessment is a proactive approach to eliminating failures. On average, The Company encounters five failures a year. The Company seeks to minimize these failures by implementing this program. Transformer failures inevitably occur, but The Company aims to minimize the likelihood of failures by annually performing a condition assessment of each transformer and prioritizing its replacement based on its condition.

Our transformer fleet is aging. Over 50% of The Company's transformer population is between 35 and 60 years old. Although our program focuses heavily on the condition of a transformer, older units have experienced more through faults, thus causing insulation deterioration, accelerated aging and poor electrical/mechanical condition. Additionally, older units are more unlikely to withstand through faults. Replacing the aging fleet should improve transformer condition, transformer efficiency and maintenance costs, thus improving network reliability.

Public and employee safety will improve if fewer transformer failures occur. Replacing transformers that are in poor condition will reduce the risk of outages, catastrophic events, and random failures.

As The Company prioritizes transformers for replacement based on condition and risk, this program also employs a contingency plan for those units on the list for replacement. Units most likely to fail are placed on a "Watch List" and a plan is developed. These units will receive closer attention from subject matter experts, and an increase in maintenance intervals to prevent failure. In addition, spares, mobile substations, feeder ties, and other solutions are identified and documented in case of unsuspected failure to minimize outages.

State and company environmental goals will be met by achieving fewer transformer failures, removal of older units, and mitigation or removal of PCB contained units. Several older units are suspected to be PCB contaminated (50 to 500 ppm of PCB). Replacing older units will reduce the probability of an oil leak and/or an oil containment issue.

Several regulatory targets may be impacted if a transformer is lost. Although the number of substation events is minimal, they do contribute to SAIFI and SAIDI.

Transformer failures may cause substantial customer outages. A transformer failure may affect numerous feeders, resulting in a larger amount of customers without power.

OTHER ALTERNATIVES CONSIDERED:

Option 1 – Age Based Replacement

A transformer asset replacement program based on age alone was previously in place and considered. However, this program does not capture those units that have problems based on a design issue or operating history. It also does not consider impacts such as environmental and number of customers affected. This program, based on condition and risk, accounts for a more accurate assessment of the transformer fleet and addresses the issues more directly.

Option 2 – Replace on Failure

Another transformer asset replacement program that was considered briefly was to replace substation transformers upon failure. This is a reactive approach and does not address any of the drivers underlying this program. This alternative would most likely increase SAIFI, SAIDI and CAIDI because transformer failures can affect large number of customers. In addition, without a plan, the restoration process may be longer than necessary.

CUSTOMER BENEFIT(s) OF PROGRAM:

Substation transformers are a critical asset class in the successful operation of the electrical distribution system. The main benefit of this strategy is adopting a proactive approach to reducing the risk of outages and catastrophic events. All transformers will be given an asset health (condition) score based on the following inputs:

- Available DGA, field diagnostic and test information
- Operational history, including load, faults, fault level and temperature data
- Particular manufacturer & design input
- Maintenance and inspection data
- Expected lifetime curve
- Reliability Centered Maintenance (RCM) analysis of available failure data and incident data

All transformers will be assessed for criticality based on the consequence of failure or unavailability using the following inputs:

- Impact on CAIDI, SAIFI, SAIDI, CMI and CI statistics
- Input from system operation and system planning
- Availability of spares, mobile units and replacement complexity

All transformers will be ranked in terms of risk (consequence of criticality and health), and targeted for replacement based on risk and the constraints of the business. The implementation of this strategy will reduce the risk of outages, catastrophic events, and random failures.

Safety and Environmental - Fewer transformer failures, removal of older units, and mitigation or removal of PCB contained units reduces the probability of an oil leak and oil containment issues. Public and employee safety will increase with newer, updated equipment.

Reliability – Substation transformer failures and events over the past ten years have been minimal at 18 events per year on average (as reported in IDS). This represents approximately 9,500 customers interrupted and 1.2 million customer minutes. This results in a SAIFI of 0.006, a SAIDI of 0.763 and a CAIDI of 127.6 minutes. Transformer failures mainly occur because of through faults, while the majority of event causes are deteriorated equipment (38%) followed by animals (15%). Animals, lightening, etc. cause external through faults which further deteriorates transformer health. Although transformer events and failures are minor, a transformer event effects a large number of customers (>1000). Implementation of this strategy will proactively minimize unreliability by identifying those transformers needing replacement based on poor condition, elevated risk and those that are critical to the system. In addition, establishing a transformer watch list will help prevent outages, and a contingency plan may alleviate long outage durations and restore customers more quickly.

Customer/Regulatory/Reputation – Minimizing large-scale interruptions and safety and environmental hazards as discussed above will improve relations with all stakeholders.

Efficiency - This program will reduce the number of transformer failures per year by replacing those units most likely to fail. An identified number of transformers will be watched and monitored by subject matter experts during the interim prior to replacement. A plan of action will help restore customers quickly if an unsuspected event or failure occurs. As an example, three transformers at Heuvelton Station were retired due to condition; they were removed from the system in a controlled manner to avoid possible failure.

METRICS TO TRACK BENEFIT(s):

The number of transformer failures on a yearly basis will continue to be tracked. Ongoing measurements will be performed on SAIDI/SAIFI improvements by comparing what would have happened in the absence of a planned, prioritized transformer replacement list.

Tracking of SAIFI in relation to transformer failures and outages should be analyzed to determine if the number of outages have decreased on those units that were replaced due to poor condition.

Tracking of SAIDI and CAIDI in relation to substation transformer failures or outages should be analyzed to determine if the "Watch List" and contingency plan has improved our ability to react quickly.

EXHIBIT 50

PROGRAM NAME:

Batteries and Chargers – Asset Replacement

PROGRAM DESCRIPTION:

The intent of this program is to have no battery system greater than 20 years old on The Company's system. The Company established this 20 year limit based on industry best practice and our experience in managing battery systems. Battery systems (or sets) are at the heart of a substation's operational capability and provide the power to charge breaker coils which allow the breaker to operate successfully. Therefore, these systems are of significant importance in ensuring a sustainable distribution system and maintaining system reliability.

DRIVER(s):

Substation batteries and chargers play a significant role in the safe and reliable operation of substations. Batteries and chargers provide DC power for protection, control and communications within the substation and between substations and control centers. Battery systems on each substation are checked for leaks and degradation during bimonthly V&O inspections. An annual test of each battery system is performed to confirm condition.

The Company Substation Maintenance Standards identify the expected life of substation batteries and chargers as twenty years. This timeline is in line with industry expectations and manufacturer guidelines. The Company also issues maintenance bulletins relating to specific battery types where individual cells have an increased rate of deterioration or impaired performance.

A program to replace battery systems on condition or at end of asset life as per The Company standards is in place. Where appropriate, the battery charger is replaced at the same time as the battery system.

Approximately 20 battery related problems have been recorded in the Problem Identification Worksheet (PIW) system. These have all been addressed through ongoing battery related projects.

Given current costs and current replacement rates The Company has developed a ten year replacement program to bring all battery sets in line with the twenty year standard.

OTHER ALTERNATIVES CONSIDERED:

An alternative would be to do nothing and replace batteries and chargers as they fail. The Company rejected this option because it could result in significant impacts on reliability because potential problems such as the failure of a circuit breaker opening or closing would adversely affect reliability and possibly result in additional equipment damage.

The approach of deferred replacement: this option was rejected as inappropriate because the risk of failure of these assets increases with age.

CUSTOMER BENEFIT(s) OF PROGRAM:

Reliability
However, by failing to meet the twenty year standard it is likely that we will see an impact on reliability since substation batteries are used for protection, monitoring, and control within most substations. Failure of equipment or protection schemes to operate properly may lead to cascading events within the system.

Customer / Regulatory / Reputation
This strategy will assist in ensuring battery systems meet current operating requirements and will perform their designed function and not impact customers or The Company adversely through mis-operations of equipment or protection schemes.

Efficiency
By changing battery systems and chargers simultaneously there is a cost efficiency in replacing batteries on a planned basis as opposed to during an emergency situation.

METRICS TO TRACK BENEFIT(s):

Replace batteries in the time frame identified within the program.

Track batteries related failures or mis-operations through AIMMS or IDS.