National Grid

Niagara Mohawk Power Corporation

INVESTIGATION AS TO THE
PROPRIETY OF PROPOSED
ELECTRIC TARIFF CHANGES

Testimony and Exhibits of:

Infrastructure and Operations Panel

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NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

The Infrastructure and Operations Panel

Dated: January 29, 2010

Testimony of the Infrastructure and Operations Panel

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Testimony of the Infrastructure and Operations Panel

I. Introduction and Qualifications

Q. Please introduce the members of the Infrastructure and Operations Panel.

A. The Panel consists of Ellen Smith, Bruce Walker and Keith McAfee.

Q. Ms. Smith, please state your name and business address.

A. My name is Ellen Smith. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, and serve as Executive Vice President and Chief Operating Officer ("COO") for Niagara Mohawk Power Corporation d/b/a National Grid (the "Company"),[1] as well for Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, in Massachusetts, Granite State Electric Company d/b/a National Grid, in New Hampshire, The Narragansett Electric Company d/b/a National Grid, Rhode Island, and New England Power Company, which owns and operates transmission

[1] Throughout this testimony, the panel will refer to National Grid plc as "National Grid," National Grid USA Service Company as "Service Company," and Niagara Mohawk Power Corporation d/b/a National Grid as "Niagara Mohawk" or "the Company." Service Company provides services to all of National Grid's U.S. affiliates, including Niagara Mohawk.

assets in Massachusetts, New Hampshire, Rhode Island, and Vermont. I am also responsible for operating the transmission, distribution and generation system on Long Island, New York as part of a service agreement with the Long Island Power Authority. As Executive Vice President and COO of National Grid plc's U.S. Electric Distribution, Generation and Transmission organization, I oversee approximately 6,000 employees and $11.7 billion of infrastructure assets serving over 4.6 million customers in the Company's U.S. service areas. In that capacity, I am responsible for all aspects of the Company's electric delivery system serving customers in Upstate New York, including the asset management, engineering, design, construction, operations and maintenance of the Company's electric distribution and transmission facilities.

Q. Please describe your educational background and business experience.

A. I am a graduate Onteora Central High School in Boiceville, New York, and attended Union College in Schenectady, New York, where I earned a Bachelor of Science degree in Mechanical Engineering and a Master of Science degree in Power Systems Engineering. I am a licensed Professional Engineer in New York State. Prior to joining National Grid, I worked for the Hess Corporation for 5 years as the President of Hess

Microgen, which was in the business of building and servicing co-generation and small distributed generation facilities, and most recently, as the Vice President of Refinery Optimization, significantly improving the power and utility operations at the Hess Joint Venture Oil Refinery (HOVENSA, LLC) on St. Croix. Prior to Hess Corporation, I was President of Pratt &Whitney Power Systems for 5 years. I also spent over 18 years at GE Energy in various commercial and technical roles serving utility and industrial customers, and prior to that was with New England Power Service Company for 1 year as an associate engineer.

Q. Mr. Walker, please state your name and business address.

A. My name is Bruce Walker. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid as the Vice-President of Asset Strategy and Policy. In this capacity, I am responsible for analyzing reliability information throughout National Grid**,** establishing appropriate data governance to ensure the integrity and usefulness of the reliability data, developing appropriate asset strategies and policies consistent with the information obtained from analyzing the system and sustaining a viable network, and initiating research, development and demonstration projects for the distribution and sub-transmission systems throughout National Grid's service territory in the United States.

Q. Please describe your educational background and business experience.

A. I am a distinguished graduate of the United States Air Force Academy Preparatory School and thereafter received a Bachelor of Electric Engineering degree from Manhattan College and a Juris Doctor in Law from Pace University where I was the technical editor on the Environmental Law Review and received an Environmental Law Certificate. I also completed the 18 month Power Technologies Inc. (now Siemens Inc.) Distribution System Engineering course. Prior to beginning with National Grid in 2008, I worked in the utility industry for nearly 18 years for Consolidated Edison of New York, Inc. and Orange and Rockland Utilities in various capacities, including; various positions in Electric Operations, Mergers and Acquisitions, Regulatory Services and Emergency Management. I was appointed by the U.S. Secretary of Energy to the Electricity Advisory Committee in 2008 representing investor owned utilities and I was recently elected to the Board of Directors for GridWise Alliance.

Q. Mr. McAfee, please state your name and business address.

A. My name is Keith McAfee. My business address is 1125 Broadway, Albany, NY 12204.

Q. By whom are you employed and in what capacity?

A. I am employed by Niagara Mohawk Power Corporation d/b/a National Grid. I am Vice President of Operations for the Eastern Division of New York. In that capacity I am responsible for the supervision of professionals and field forces who operate, maintain and construct the Company's electric infrastructure in that area.

Q. Please describe your educational background and business experience.

A. I graduated from Clarkson University in 1985 with a Bachelor of Science in Electrical Engineering. I received a Masters of Business Administration from New Hampshire College in Manchester, New Hampshire in 1991. I am a licensed Professional Engineer in New York State. I also completed the 18-month Power Technologies Inc. (now Siemens Inc.) Distribution System Engineering course.

I joined National Grid in 1992 as an Account Manager in Buffalo, NY. In 1994, I was promoted to Technical Services Manager in Albany, NY. In 1999, I was promoted to Regional Manger for the Northeast Region in Glens Falls, NY. In 2002, I was promoted to Director of Customer Operations for the Eastern Division of New York and in 2007 I was promoted to my present position Vice President of Operations, Eastern Division of New York.

Prior to National Grid, I was employed by Central Hudson Gas and Electric from 1985 through 1987 as an Associate Engineer in Newburgh, NY. Between 1987 and 1991, I held various operations management and engineering positions for Public Service Company of New Hampshire in Manchester and Nashua NH.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of the panel's testimony?

A. The purpose of our testimony is to describe the Company's electric infrastructure investment and operations plan necessary to manage its electric system for the period covered by this rate case. The testimony includes a comprehensive overview and detailed description of the infrastructure investment plan for the rate period and the incremental costs included as part of the operations and maintenance cost of service for the same period. The testimony also describes the methodology by which the Company manages the entire system and thereby develops and prioritizes its annual work plan and budget. Furthermore, we describe how the Company executes the annual work plan and key initiatives it is engaged in to manage its responsibilities.

Niagara Mohawk's service territory encompasses approximately 25,000 square miles in more than 450 cities and towns, and serves approximately 1.6 million electric customers. The Company's physical assets include more than 6,002 miles of transmission lines (4,815 miles of 115 kV lines, 504 miles of 230 kV lines, and 683 miles of 345 kV lines as of December 2008), and 313 transmission substations. National Grid has more than 4,500 miles of sub-transmission lines (3,400 overhead, 1,100 underground) on 64,000 towers/poles. These transmission and sub-transmission facilities serve 441 distribution substations supplying a distribution system consisting of more than 800 power transformers, 4,000 breakers, 42,800 circuit miles (35,900 overhead, 6,900 underground) of primary on over 1,200,000 poles and 442,000 line transformers.

Q. Please describe the Company's overall objective with the infrastructure and operations plan presented here.

A. Primarily, the plan is developed to meet our regulatory obligations which include providing safe, reliable, efficient, and environmentally sound electric service for customers at reasonable costs. The plan includes capital and operations and maintenance ("O&M") spending needed to meet state and federal regulatory requirements applicable to the electric system, address load growth/migration, maintain reliable service, sustain asset viability through targeted investments driven primarily by condition assessment, and fund those investments necessary to accommodate new public policy initiatives and technological developments, including the integration of renewables that affect the electric system.

Q. What format does the panel use to present the Company's infrastructure investment plan?

A. Our testimony presents the infrastructure investment plan in relation to the Company's fiscal year budgets. The Company's fiscal year is defined as the 12 month period from April 1 of a year, through March 31 of the following year, with the fiscal year being the end year. Thus, fiscal year 2010 ("FY10") would be the period April 1, 2009 – March 31, 2010. Throughout our testimony, we refer to budgets for the period FY11 – FY

14 (April 1, 2010 – March 31, 2014). These budget periods span the period covered by this rate case filing (January 1, 2011 – December 31, 2013).

The Company manages its infrastructure investment plan and other business operations on a fiscal year basis, and has presented prior investment plan information to the Commission and Department of Public Service Staff on a fiscal year basis for the past several years. Presenting the infrastructure investment information in this case on a consistent fiscal year basis facilitates comparison of the Company's current plan with prior submissions and investment requirements established by the Commission in other cases.

Although the Company's investment plan is presented on a fiscal year basis, the revenue requirement in this case is developed on a calendar year basis, as presented in the testimony of the Revenue Requirements Panel. The effect of the Company's capital investments on revenue requirements is affected by the estimated in-service dates for such investments. Our testimony describes briefly how in-service dates were determined for the infrastructure investments presented in the plan, and a more detailed discussion is also presented in the testimony of the Revenue Requirements Panel.

Q. How much is the Company planning to invest through its infrastructure investment plan during the FY2011-FY2014 period?

A. Niagara Mohawk plans to invest $424 million to improve its electric delivery infrastructure in fiscal year 2011 ("FY11"), $536 million in FY12, $613 million in FY13 and $635 million in FY14. In FY 2010, it estimates it will spend $378 million. Exhibit __ (IOP-1) depicts forecast and planned capital investment for the period FY10-FY14, on the basis of investment category as well as network segment. This exhibit also includes electric infrastructure program and project detail information which is described and referenced later in our testimony. The investment categories used by the Company in development of its infrastructure investment plan are also described in detail, below.

Q. Do the investment levels you mention include all of the capital investment reflected in the Company's revenue requirements in this case?

A. No. The annual infrastructure investment amounts mentioned do not reflect costs associated with the payment of $35 million associated with the Tri-Lakes project, or $57 million associated with the Luther Forest Technology Campus, each of which is described in detail in our testimony. In addition, the Company plans to make facilities and properties related capital investments during the rate plan period, as well as investments in information systems and technology, fleet, inventory management and investment recovery functions. These investments are needed to enable the Company to continue to provide safe and reliable service to customers, and are key to the Company's infrastructure and operating plans going forward. The levels of planned capital investments in properties and facilities are set forth in Exhibit __ (RRP-6), Schedule 1, Sheet 4, of the Revenue Requirements Panel's testimony, and are approximately $36.4 million in FY11, $32.4 million in FY12, and $4.4 million in each of FY13 and FY14. Additionally, planned Information Systems capital investments equal $5.1 million in FY11, $4.2 million in FY12, and $4.1 million in FY13. Finally, our testimony supports capital investment of approximately $0.6 million annually related to fleet services, inventory management and investment recovery.

Q. Does the Company's filing in this case reflect the amount of capital investment anticipated in the period from the end of the historic test year until the start of FY 2011?

A. Yes. The historic test year ended September 2009, and the investment plan period described in this filing commences April 1, 2010. For the period October 1, 2009 – March 31, 2010, the Company anticipates capital spending of $229 million on electric infrastructure and general plant, $4.5 million on Information Systems, and $11.3 million on facilities. These amounts are reflected in Revenue Requirements Panel Exhibit __ (RRP-6), Schedule 1, Sheet 4, and the supporting workpapers.

Q. How does the Company's infrastructure plan presented in this case compare to previous plans the Company has developed?

A. Our testimony describes how the infrastructure plan was developed and how it is structured. In those regards, the plan presented here is similar to prior plans. However, the plan presented here is a substantial reduction from previously developed plans which the Commission and its Staff have seen. The current plan reflects the Company's attempt to minimize the level of investment needed during the rate plan period, consistent with its obligation to continue to provide safe and reliable service, in order to mitigate the rate impact on customers. The Commission and its Staff have sent clear messages on the need for the State's utilities to take steps to practice austerity and to manage rate impacts to address the needs of customers during the current economic downturn, and the Company's current infrastructure plan is a response to those messages.

The plan that we are filing does not represent what we believe to be an optimal level of infrastructure investment. In January 2009, the Company filed its five-year Capital Investment Plan reflecting planned electric infrastructure investment of $3.57 billion for the period FY10-FY14. Throughout 2009, the Company continued to evaluate and refine its investment plan as it developed or became aware of new information and circumstances. In December 2009, the Company met with Staff and presented an infrastructure investment plan that reflected a substantial reduction from the investment levels included in the Company's January 2009 Capital Investment Plan filing in Case 06-M-0878. The reductions reflected our effort to reduce investment costs to a minimum level consistent with maintaining near-term reliability and sustaining the system over the rate plan period. We took this action mindful of reducing rate impacts to customers. The December plan presented to Staff continues to represent what we believe to be a preferred level of capital spending even in these difficult economic times. Nonetheless, in response to Staff's feedback and the Commission's December austerity order, we are proposing in this case a plan that reduces our proposed level of capital investment further, resulting in a proposed level of investment of $2.3 billion (including the Luther Forest and Tri-Lakes projects) for the FY11-FY14 period. Exhibit __ (IOP-2) provides a comparison, by year, of the infrastructure investment plan reflected in this rate case and the Company's January 2009 Capital Investment Plan filing.

Q. Could you provide examples of changes reflected in the plan presented here compared to what the Company presented to Staff in December?

A. The Company carefully evaluated its investment plan to identify projects that could be deferred or re-phased without substantially reducing near-term reliability or risking non-compliance with mandatory requirements. Over the current Company's 5-year capital budget cycle (FY11-FY15), we identified deferrals of over $350 million of work from the December 2009 plan presented to Staff. Some of these deferred projects include: Ticonderoga Lines rebuild (moved out to FY14+); Priority 3 & 4 Oil Circuit Breakers (reduced and moved out to FY14+); Gardenville-Homer Hill 151/152 phase 2 (moved out to FY14+); Rotterdam Station rebuild (moved out to FY14+); and strategy to reinforce the transmission system in the Frontier and Southwest regions (N-1), (N-1-1) (re-phased).

Although our proposed plan carries with it increased reliability risks, all else being equal it should enable us to meet the reliability targets that we are proposing for the period of this rate case. It should be noted, however, this plan reflects a minimum level of spending necessary to maintain reliability in the near term. Ultimately, the investments removed from this plan will need to be addressed to sustain reliability in the future as the reduced capital spending in this plan is largely the result of deferring work.

Q. What value will the Company's proposed capital investment plan provide to customers?

A. Our proposed capital investment plan reflects the minimum level of spending that is consistent with achieving our proposed reliability targets in the near-term and making small progress towards addressing some of the longer term reliability risks faced by our customers. The plan will permit us to meet statutory and regulatory requirements and to replace equipment that is damaged or that fails. It will also permit us to address a limited set of system capacity and performance issues and asset condition problems. An optimum level of investment would remediate more system capacity and performance issues and asset condition problems. The proposed plan thus strikes an uncomfortable but reasonable balance between reliability and austerity. It holds costs to customers to the minimum reasonable level consistent with near-term reliable service.

Q. What would be the consequences to customers of deferring by a year some of the projects included in your proposed plan?

A. This question is best answered by discussing the categories of investments that we would defer if the Commission were to approve a lower level of investment than we are proposing and the consequences of deferring those investments.

The Company's plan is developed on the basis of five primary investment drivers, or categories, and is presented in that manner in this testimony. These categories, which are described in detail later in our testimony, are: (1) Statutory or Regulatory Requirements; (2) Damage/Failure; (3) System Capacity and Performance; (4) Asset Condition and (5) Non-infrastructure. Investments in these categories range on a spectrum: work in the Statutory or Regulatory Requirements and Damage/Failure categories is considered mandatory, while work in the System Capacity and Performance and Asset Condition categories is more discretionary. Non-infrastructure work supports work in the other categories.

As indicated in Exhibit __ (IOP-1) schedule 1, sheet 1 of 1, almost 45 percent ($983 million) of the planned infrastructure spending will be mandatory work in the statutory/regulatory requirements and damage/failure categories. Examples of investments in this investment category include work on Niagara Mohawk's Clay and Porter substations to bring them into compliance with Northeast Power Coordinating Council ("NPCC") design, protection and operation standards, or capital work done to repair a portion of a distribution feeder damaged in a storm event or extend service to new customers.

This work could not be deferred for a year without potentially violating mandatory reliability standards, degrading near-term service reliability to existing customers or delaying service to new customers.

The system capacity and performance category accounts for approximately 23 percent ($502 million) of the total spending, and includes such things as investments to ensure substations and feeders can reliably supply customer load within system design criteria. Examples of investments in this category include planned expansions and network upgrades to accommodate load growth associated with the new University of Buffalo Medical Complex, expansion of the Albany Medical Center and St. Peter's Hospital, and the medical complex in the Syracuse University area.

The asset condition portion of the plan represents nearly 32 percent ($690 million) of total planned spending for the FY11 to FY14 period. Programs in this category aim to mitigate future risks and consequences of potential failures caused by deteriorated assets. An example of a program in this category is the rebuilding of the Gardenville station, which is a 230/115kV complex south of the Buffalo area. This part of the network includes a substation that feeds regional load via eleven 115kV lines, and that has serious asset health issues including, but not limited to, control cable, breaker, disconnect and foundation problems. The station has had no major upgrades since it was built in the 1930s.

Deferring capital investment on projects in the system capacity and performance and asset condition categories would create greater reliability risk. The Company has more discretion with respect to the timing of when to proceed with investments on projects in these two categories than on projects that are in the statutory/regulatory requirements or damage/failure categories. If the Commission were to approve a lower level of capital investment than the Company is proposing, the additional work that we would defer would generally be those in these two categories. However, the proposed projects in the system capacity and performance and asset condition categories would still need to be done. Deferring them by a year or more would increase risk. There is not a direct correlation between levels of investment in a particular year and the corresponding reliability performance in that year. What we know, however, is that the system capacity and performance and asset condition projects included in our plan are only a subset of all the system capacity and performance and asset condition projects that have been identified by the Company. The ones included in the plan are included precisely because they are the ones that we have determined carry the greatest risk to reliability, safety or the environment. They are included in the plan because we have concluded that deferral is not an appropriate option even during this time of austerity.

A detailed discussion of the spending categories, as well as the underlying investments that make up these categories is included as part of the detailed infrastructure investment section of this testimony.

Q. Please summarize the panel's testimony regarding the costs of operating the electric system.

A. In addition to supporting the Company's infrastructure plan and other capital investments, we also address major expenses associated with operating the Company's electric delivery system, and in particular we describe incremental operations and maintenance ("O&M") expenses the Company expects to incur in connection with operating its electric system during the rate plan period as compared to corresponding O&M expenses in the historic test year period. Among the major O&M expense changes we describe in our testimony are:

- Increased costs from enhanced inspection and maintenance requirements;
- Tower painting and comprehensive aerial patrol, and footer inspection costs;
- Costs associated with enhanced vegetation management;
- Increased O&M and labor expense relating to the level of infrastructure investment;
- A proposal to implement a fully reconciling "storm fund" to reflect more accurately the historic expenses incurred in connection with extraordinary storm events; and
- Increased site investigation and remediation (environmental) costs.

A detailed discussion of the major expenses is included as part of the Operations and Maintenance Expenses section of this testimony.

Q. Does the panel propose any tracking mechanisms related to capital or operating expenses presented in this plan?

Yes, the panel proposes a mechanism for tracking and reconciling certain deviations from capital investment budgets, including costs related to third-party activities outside the Company's control that affect the Company's operation of the electric system (e.g., third-party transmission-related costs). Details on the tracking mechanism and its operation are included in the testimony of the Revenue Requirements Panel.

Q. Does the panel address the recommendations presented in the recent Comprehensive Management Audit Report in Case 08-E-0827?

A. In accordance with the Order issued and effective on December 18, 2009 in Case 08-E-0827, the Company has developed an implementation plan addressing the recommendations presented in the management audit report. A copy of that plan is being filed in that case, and is also included as an exhibit to the testimony of Mr. Peter Zschokke in this case. As Mr. Zschokke's testimony describes, the Company has commenced implementation of several of the recommendations in the management audit report, including recommendations affecting the implementation of infrastructure investment plans and electric system operations. Although our testimony touches on some of the recommendations in the report and some of the things the Company is doing to address those recommendations, details of the Company's specific proposed implementation steps associated with individual audit recommendations are set forth in the implementation plan included with Mr. Zschokke's testimony.

Q. Does the Company discuss measures it is taking in response to the Commission's December 22, 2009 Order Approving Ratepayer Credits in Case 09-M-0435?

A. Yes. The Company continually seeks to improve efficiency in service, and our testimony describes some of the Company's cost-containment efforts needed to achieve its ambitious performance and productivity objectives. In addition, however, and in response to the Commission's directive, the infrastructure investment and operations plan in this case reflects further efforts by the Company to identify cost savings measures that would inure to the benefit of customers during the rate plan period, and we describe some of those efforts and considerations in our testimony.

In some cases, the deferral of infrastructure investment will require interim mitigation operations and O&M spend.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. In connection with our testimony, we are sponsoring the following exhibits, which were prepared by one or more members of the panel or under their supervision and direction:

Exhibit __ (IOP-1): Forecast and planned T&D infrastructure investment levels by category, FY10-FY14;

Exhibit __ (IOP-2): Comparison of T&D Capital Expenditures FY10-to-FY14; NMPC Rate Case Filing vs. January 2009 CIP Filing;

Exhibit __ (IOP-3): Electric Reliability Performance 2005-2009;

Exhibit __ (IOP-4): Illustration of the project evolution process;

Exhibit __ (IOP-5): Facilities and properties capital expenditures;

Exhibit __ (IOP-6): Summary listing of information system projects;

Exhibit __ (IOP-7): January 15, 2010 Mobile Stray Voltage Testing Project report;

Exhibit __ (IOP-8): Inspection and maintenance incremental cost support;

Exhibit __ (IOP-9): Incremental cost support for tower painting; comprehensive aerial inspections; and footer inspections;

Exhibit __ (IOP-10): Incremental cost support for vegetation management activities;

Exhibit __ (IOP-11): Calculation of Storm Fund level;

Exhibit __ (IOP-12): Schedule of site remediation activities; and

Exhibit __ (IOP-13): Summaries of planned research, development and demonstration projects.

The Panel also includes workpapers in the form of the Company's Annual Transmission and Distribution Capital Investment Plan, filed in Case 06-M-0878, on January 29, 2010, the Report on the Condition of Physical Elements of Transmission and Distribution Systems, filed in Case 06-M-0878 on October 1, 2009 and supporting strategies, all of which are collected in Exhibit __ (IOP-14).

Q. How is the remainder of your testimony structured?

A. The remainder of our testimony includes:

- A summary of Niagara Mohawk's approach to managing the electric system;
- A description of the Company's infrastructure investment plan, including a description of major programs and projects driving the investment plan;

- A description of the Company's facilities and properties plan over the period covered by this case;
- A listing and description of the major information systems projects to be implemented during the rate plan period that are needed to implement Niagara Mohawk's infrastructure and operating plans;
- A description of the Company's O&M expenses, and particularly significant changes or initiatives driving known and measurable changes in costs in the period covered in this case as compared to the historic period;
- Descriptions of planned research, development and demonstration initiatives associated with the electric system;
- A brief description of efforts the Company undertakes in the areas of safety and environmental stewardship; and
- A request for modification of certain reporting requirements.

III. The Company's Approach to Managing the Electric System

Q. Describe the Company's philosophy and objectives underlying the development of its infrastructure investment and system operations plans.

A. As an energy delivery company, Niagara Mohawk's fundamental goal is to provide safe, reliable, environmentally sound and efficient electric service to customers at reasonable cost. In recent years, achieving this goal has become an increasing challenge for a variety of reasons. These include the deteriorated condition of many of our electric delivery system assets (consistent with their age profile), the obsolescence of various classes of assets, the need to accommodate changing and dynamic power flows, increasing power quality and reliability demands of our customers, volatility in the availability of and competition for commodities and equipment, and uncertainty in the economic, policy and technological climates influencing the electric utility industry. Looking forward, it is our sense that these challenges will only intensify, driven by public policy and legislative initiatives promoting new technologies, continued focus on energy efficiency, as well as a need to support societal efforts on climate change and environmental issues. It is within this challenging and dynamic framework that the Company develops and continually refines its infrastructure investment and operations plans.

Q. Describe the Company's approach to managing the electric system.

A. The Company's approach to managing the electric system has evolved over time. Over the past several years, the Company has shifted its operating focus from a reactive, repair-oriented approach to one driven by a well-defined asset management framework that embraces a portfolio of asset management techniques. In the past, the Company, like many other electric utilities, conducted much of its infrastructure maintenance and replacement activities based on the results of periodic engineering studies of asset performance or known operating deficiencies, rather than on the basis of data collected using a systematic process of inspection, data collection, and analysis.

The term "Asset Management" describes the systematic and coordinated activities and practices through which an organization optimally and sustainably manages its assets and asset systems, and their associated performance, risks and expenditures over their life cycles for the purpose of achieving its organizational strategic plan. Specific to the Company, this can be summarized as; the process used to manage the Transmission and Distribution system infrastructure and the electric system to ensure safe, reliable, efficient and cost effective service over the life cycle of the assets and asset systems. This includes work aimed at alleviating loading constraints and increasing capacity in specific areas to improve the reliability of service as well as asset condition projects aimed at rebuilding or upgrading system elements such as overhead lines, underground cables, substation equipment and network control systems. The Company adopted the asset management approach because it is best suited to manage a large number of physical assets and provides the best long-term value for customers.

The systematic approach associated with the asset management process targets specific assets for intervention based upon their condition. Candidates for intervention are selected based upon their current performance or condition and their forecast performance and condition based on known degradation mechanisms. Although age alone is not a reliable indicator of condition, it is an important factor when considering the volumes of assets that need to be managed to ensure long-term sustainability with acceptable reliability performance. Age is also an important attribute to assess assets that are beyond design life, at the end of useful life and/or obsolete, making maintenance cost-prohibitive or impossible.

The Company's Asset Management process includes developing "strategies." Strategies are documented standards or policies (Company or industry) against which assets and/or asset systems are assessed with respect to condition, performance, capacity and other factors. Strategies define "what" will be done, by setting forth systematic, coordinated activities and practices designed to result in the optimal management of assets and asset systems over their respective life cycle, to address either deficiencies in asset condition and performance, or non-compliance with internal and / or mandatory external planning standards. Strategies incorporate information obtained from system studies, industry knowledge, trend analyses and inspection, maintenance and replacement programs in order to achieve specific operating objectives for the respective asset class or asset system. Strategies result in implementation plans, in the form of programs or projects. These programs and projects describe 'how' the Company executes its Strategies and thus plans to manage and optimize asset performance and lifecycles. For example, the Overhead Line Refurbishment Strategy describes the efforts the Company will utilize to manage its overhead transmission line assets over the next 25 years based on an understanding of current conditions and forecast deterioration. Based on this strategy, a portfolio of approximately 30 projects has been defined to address what needs to be done for individual overhead lines to achieve the overall objective of the overhead line refurbishment strategy.

The Company's systematic approach to asset management uses a consistent scoring system that prioritizes all assets for replacement or upgrade based upon the likelihood and consequences of failure, and criticality to the system. Using this approach, the highest priority assets (i.e. those with the highest risk score and potential adverse impact to system safety, reliability, and the environment) are replaced first.

Q. What prompted the Company to move to a proactive, asset-management approach?

A. Infrastructure businesses throughout the world that manage large volumes of similar assets use asset management principles to manage asset life cycles in order to reduce the potential for unplanned failures, or having large populations of assets fail contemporaneously, requiring significant replacements over short periods of time. Such situations are highly undesirable since the lead time for major equipment (e.g., high voltage circuit breakers and power transformers) and work delivery (e.g., transmission line work) can easily be several years. Over the past ten years, the Company has seen increasing evidence of deteriorating conditions and performance on its system. Such deterioration is not out of the ordinary[2]; indeed, some deterioration is to be expected with greater service factor and age of an asset. Because of the long service lives of

[2] As noted in the Energy Infrastructure Issue Brief developed in connection with the State Energy Plan process, portions of the State's transmission and distribution system are in need of attention to ensure reliability in the future, as evidence by investor-owned utilities' plans to spend $13 billion over the five-year period between 2009 and 2013. See, http://www.nysenergyplan.com/final/Energy_Infrastructure_IB.pdf , p. 19.

many of the Company's assets, and the fact that many assets were nearing the end of their service lives, the Company needed to adopt a systematic and proactive asset management approach or face the potential for a future "wall" of unplanned asset replacement due to failure.

Q. Can you provide an illustration of your statement regarding the deteriorating conditions of assets on the Company's system, and how a proactive asset management approach might serve to address the situation?

A. Replacing and renewing assets in a systematic manner is advantageous in at least two significant scenarios: one associated with low cost, large volume assets; and the other with high cost, lower volume assets. Regarding the low cost/large volume items, failure to replace these assets in a timely manner will result in a huge number of assets whose asset class becomes so aged that the volume of assets to be replaced at some point in the future will be insurmountable. Steel towers and power transformers will be discussed as examples of both these scenarios.

Niagara Mohawk's steel tower asset base is in excess of 20,000 towers. The average age of steel towers on the Company's system is 68 years, with more than 67 percent of 115 kV structures being over 70 years old.

Again, although the age of a system component is not necessarily indicative of its condition or usefulness in serving customers, it is significant that a large segment of the component population is reaching the end of its useful life, anticipated to be in the range of 70-90 years. As the proportion of assets reaching the end of their anticipated service lives increases, proactive steps must be taken to reduce the compounding risk of unacceptable service consequences that could result from a high concentration of age-related equipment failure. The Company’s steel tower strategy involves inspecting all towers on a 5-year cycle and rating each based on defined criteria, maintaining the towers through a painting and footer inspection/repair process, and replacing any towers rated in poor condition.

For high cost, lower volume assets, a systematic asset management approach will provide significant benefits since the challenges to replace these assets when they fail are complex and high cost. One example is the Company’s power transformers at substations. Power transformers provide service to many thousands of customers and are the single largest capital investment in substations (which are the largest, most expensive and most complex portion of the distribution system in their own right) comprising almost 40 percent of the total investment. Power transformers deteriorate (degrade) with time and thermal operation because paper is a key component of insulation (which is a key component within the transformer) which suffers deterioration as a result of three key processes: oxidation, hydrolysis and thermal heating. The deterioration is cumulative and irreversible and thus cannot be addressed via maintenance. Nearly 50 percent of our approximately 807 substation transformers are greater than 50 years old. Thus, in twenty years, if the Company replaced 4 substation transformers per year in this age grouping (the average historical replace rate), it would still have 40 percent of transformers (or 323 units) greater than 70 years old and in total nearly 600 units (or almost 75 percent) would be greater than 50 years old. The Company's ability to efficiently and effectively replace the large number of complex assets would be compromised under such a trajectory, and system reliability and performance would be difficult to sustain. To address this situation, the Company has developed a transformer asset strategy to replace approximately 150 transformers over the next fifteen years (an average of ten transformers per year) to keep up with the aging population and to lessen the risk of unplanned failures.

Waiting to replace on failure is also not an acceptable method of managing large power transformers due to safety and environmental reasons. While the majority of power transformers fail internally, occasionally a unit may fail catastrophically, resulting in release of a large quantity of oil into the surrounding environment, or causing a fire that destroys much more than the transformer itself, such as happened at the Company's New Scotland station in 2004.

Q. Can you provide examples of what the Company has done to gain a better understanding of the condition of its transmission and distribution assets in order to implement the current proactive asset management approach?

A. Critical to any systematic and coordinated asset management process is a comprehensive understanding of the condition and performance of the physical assets over their life cycle. Good decision making requires adequate information about the assets and their associated strengths and weaknesses. In particular, it is important to understand the relationship between short-term asset management activities (maintenance, refurbishment, replacement, etc.) and their actual or potential effect upon long-term costs, risks and performance.

Historically, a substantial portion of infrastructure investment was driven by a run-to-fail and fix-on-fail methodology. Because of observed deteriorating reliability performance, and the need to provide customers with sustainable electric service, the Company implemented the proactive asset management approach based upon the principles of the Publicly Available Specification (PAS 55), "Specification for the optimized management of physical assets." PAS 55 was first published in 2004 in response to demand from industry for a standard for infrastructure asset management. PAS 55 specifically is intended to address the life cycle management of assets. Using the PAS 55 principles, the Company has implemented a process of collecting data and evaluating electric system assets through a number of inspection and monitoring programs, including:

- Dissolved Gas Analysis for all substation transformers and load tap changers;
- Aerial helicopter surveys of sub-transmission rights-of-way,
- Acoustic detection and partial discharge testing at metalclad substations;
- VLF (Very Low Frequency) testing of cables;
- Stabilized video surveys, enhanced infra-red surveys and aerial laser surveys of transmission lines;
- Substation condition assessments; and
- Asset health reviews.

The collection of condition and performance data, and the interpretation of the data to generate useful and meaningful information to guide asset management decisions, are ongoing activities to enable improved risk management. Risk management is an important foundation for proactive asset management. This approach results in defined programs and projects that reduce overall risk.

In addition to several tools and systems the Company has introduced over the past several years to improve its understanding of system condition and performance, the Company has also introduced annual asset health reviews for all its transmission and distribution substation and overhead line equipment. This annual asset health review forms the basis of the annual "Report on the Condition of Physical Elements of Transmission and Distribution Systems" filed with the PSC (and which is included with our workpapers). The asset health review provides a methodology for identifying past or existing nonconformities with respect to defined strategies. The review also captures any asset-related deterioration, failures or incidents. The review provides leading performance indicators to provide warning of potential non-compliance with performance requirements and lagging performance indicators to provide data about incidents and failures. The asset health review provides both qualitative and quantitative measures and forms the basis of many of the Asset Condition driven infrastructure investments.

Q. What has been the result of the proactive asset management approach the Company adopted?

A. Following a period of declining reliability performance in the early 2000s, the Company has demonstrated steady reliability improvement from 2004 through 2008. Preliminary results for 2009 indicate that the Company again achieved its reliability performance targets. Exhibit __ (IOP-3) depicts the Company's reliability performance against established targets for the calendar years 2005 through 2009. The Company's reliability performance is in large part a result of its proactive asset management approach, as well as a number of other initiatives aimed at making the system more robust and resilient.

IV. Description of Niagara Mohawk's Infrastructure Investment Plan

Q. Describe the Company's infrastructure investment plan.

A. As described previously, the Company takes a comprehensive and integrated approach to managing its infrastructure investment. That effort results in, among other things, an infrastructure investment plan that categorizes planned investments on the basis of the primary drivers for those investments. The five primary investment drivers the Company has established for its infrastructure investment plan are: (1) Statutory or Regulatory Requirements; (2) Damage/Failure; (3) System Capacity and Performance; (4) Asset Condition; and (5) Non-infrastructure.

Q. Please describe what is included in the Statutory or Regulatory Requirements category of work.

A. Statutory or Regulatory requirements 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"), 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 customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects. For the most part, the scope and timing of this work is generally defined by others and is non-discretionary for the Company.

Q. What capital expenditures are included in the Damage/Failure category?

A. 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.

Q. Please describe the type of projects included in the System Capacity and Performance category.

A. System Capacity and Performance projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of our customers. Projects in this category are intended to reduce degradation of equipment service lives due to thermal stress and to provide appropriate 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.

Q. Please describe the type of projects that the Company would classify as being driven by Asset Condition.

A. Asset Condition expenditures are those investments required to reduce the risk and consequences of unplanned failures of transmission and distribution assets. As discussed above, 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. The Company conducts an annual asset health assessment which includes analysis of each major asset class and asset system. The assessments focus on identification of specific susceptibilities (failure modes) and the development of alternatives to avoid such failure modes.

Q. Please describe the type of projects that the Company would classify as "non-infrastructure ."

A. In addition to the direct spending on its electric network, the Company also invests a 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 work in this category include spending for radio systems and test equipment, flood mitigation work at substations and capital repairs on substation buildings.

Q. Aside from the five investment drivers you have described, please discuss some of the Company's other considerations in the development of the infrastructure investment plan presented in this case.

A. All of the Company's recently developed investment plans reflect a disciplined and systematic approach to asset management in order to ensure the sustained safety, reliability and efficiency of the system. The plan presented in this case is similarly focused. However, in producing this current infrastructure investment plan, the Company was particularly mindful of the economic circumstances facing its customers. The Company thus challenged itself to include in the infrastructure investment plan only those programs and projects it determined to be essential or required during the period covered by the plan. Accordingly, the Company has identified opportunities to defer or reduce the scope of certain programs, such as the redesign of portions of the sub-transmission system to a looped system, and the distribution substation transformer replacement program, in order to mitigate the impact of potential rate increases on customers. As noted above, and in Exhibit __ (IOP-2), we have reduced our proposed level of capital investment in FY10-FY14 by $888 million from the level included in our January 2009 plan filed with the Commission, and substantially below our preferred level of spending presented to Staff in December 2009 after taking into account the difficult economic times. The near-term savings opportunities from such deferred investment, however, are not avoided costs. Work that is deferred from the work plan presented in this case will be required to be included in a future plan.

Failure to adequately invest in the system will also present increased risk leading to reduced reliability, and the condition of certain assets will continue to deteriorate. The Company is aware that it has the responsibility to manage these risks. This plan enables the Company to manage near-term reliability, safety and environmental risks while allowing limited progress in addressing the longer-term risks.

Q. In addition to taking a hard look at the Company's plan, what other factors contributed to reduction in the overall investment plan compared to prior plan levels?

A. The current infrastructure investment plan reflects updated economic inflation assumptions. The updated inflation adjustment reflects the recent downturn in global economies from the high inflation levels experienced a couple of years ago, and has the effect of reducing the investment level somewhat.

However, aside from such external factors, the Company also aggressively pursues continuous improvement and efficiency efforts which help it contain costs and present this reduced level plan. Such factors include a new Procurement Transformation Program, aimed at leveraging the organization's large scale to improve materials sourcing and supplier relationship management. The cornerstone of the procurement transformation process is improved strategic sourcing to drive cost savings by leveraging our scale, standardizing materials and processes, and managing demand. The program also focuses on relationship management for our strategic suppliers, aimed at improving quality, customer service, cost and innovation, and on developing improved market intelligence to support our strategic sourcing process. Underpinning the procurement transformation program is the implementation of new technologies to support the improved processes.

Another initiative the Company is undertaking to reduce costs is the introduction of Distribution Alliance Contracts and Transmission Regional Delivery Ventures ("RDV"). The RDV and the Distribution Alliance contract models, which are described in detail later in our testimony, offer the Company additional tools to enable it to reduce the costs of delivering the infrastructure investment plan.

The Company is also transforming its electric operations to improve the level of service to customers, while promoting increased safety, network reliability and performance, and efficiency. As part of this effort, know as Transformation, the Company is addressing, among other things, work management, design, construction, asset management, network operation and customer management to optimize the efficiency and effectiveness of the organization.

Q. Could you please describe the Company's Transformation efforts in more detail?

A. The central focus of Transformation is to promote a high performing organization that delivers value to customers at a high level of operational efficiency. The Transformation effort is currently focused in six core areas:

- *Asset Management*: Aimed at improving long-term planning efforts, which will enable the Company to enhance efficiencies in capital allocation and resource planning for system assets.
- *Customer Management*: Developing a Customer Order Fulfillment function to manage the customer relationship from initial inquiry to delivery of the first bill, which will streamline interactions with customers and increase customer satisfaction.
- *Contracting Strategies*: Establishing new performance-based construction contracts that encourage effective management and delivery of construction and maintenance services (e.g., the new RDV initiative mentioned above).
- *Work Delivery*: Establishing streamlined processes to ensure optimized work flow and resource utilization. Greater efficiency will be achieved in readying crews and equipment for deployment in the field and focus will be placed on crew productivity and safety.

- *Construction Design*: Creating design centers of excellence to standardize the design process and improve efficiency.
- *Network Operations*: Consolidating and standardizing network control centers and adding advanced distribution automation technologies to increase efficiency and improve service reliability.

Q. Could you provide examples of the ways in which operational efficiencies and long-term cost containment will be achieved through Transformation?

A. Specific examples of cost-containment efforts would include:

- *Centers of Excellence*: The Company's analysis shows that design personnel may spend up to 40 percent of their work day responding to customer queries for information. The Company is implementing a customer order fulfillment function to handle these customer inquiries, which will enable the design staff to focus most of their time on completing design activities. This change would not only reduce design costs (by increasing productivity of the current work force), but also improve the customer experience since the customer would have access to more resources specialized in customer interactions. The Company has created an Estimating Center of Excellence to focus on the process and delivery of high quality, timely, and more accurate project and program estimates. Improving the quality of estimates translates into a more accurate overall capital plan budget. The Company is centralizing administrative support services for field operations. This change is removing administrative work from field (now referred to as performance supervisors) supervisors in order to increase the amount of time supervisors spend in the field. This greater level of productivity will ensure improved work flow, safety assurance and productivity. Centralizing the transactional work will ensure adherence to standard processes resulting in improved accuracy, timeliness and completeness of information related to work performed, assets placed in service, and other company records.

- *Integrated Strategic Planning*: The Company is implementing new integrated planning processes to support both the long-term (up to 15 years) and short-term (0-18 months) project horizons. This change will have the effect of allowing for the more efficient planning and allocation of resources, improved procurement strategies and better contracting decisions. For example, with a longer term planning horizon, the Company will be in a position to secure longer term pricing arrangements, which are typically more cost-effective than short-term strategies.

- *Improved Work Processes*: The Company's evaluation of existing processes shows that field staff productivity can be improved through the completion of ancillary tasks such as stocking and preparing vehicles by employees other than those performing work in the field. The Company has identified new roles and responsibilities to address these opportunities, including: creation of a work readiness role that will prepare trucks and work assignments for daily crews; enabling performance supervisors to be in the field with the crews providing for visibility and coaching; and scheduling and preparing for a four week look ahead work plan.

Q. Will the Company incur costs in order to accomplish some of the changes that are necessary to achieve long-term cost reductions and productivity gains?

A. Yes it will. Although efficiency gains may be achieved through process changes and organizational tactics that do not involve significant costs, more significant efficiency gains require up-front investment in systems and equipment to automate work processes, improve worker productivity in the field, and achieve the Company's targeted level of productivity improvements.

Q. What are some of the key investments the Company is making as part of Transformation?

A. Costs associated with delivering the savings expected from Transformation include costs of new technology and systems, labor associated with implementing the new systems and processes, consultant and contracting costs, revised collective bargaining agreements, facility consolidation costs, and employee costs (for relocation, retention and severance). In return for these investments, the Company expects to achieve costs savings from the automation, standardization and integration of business processes and related information systems. Automation will require significant investment to purchase or modify the respective information-system technologies and resulting cost reductions benefit customers. In addition, the Company plans to continue to explore opportunities to leverage the scale of National Grid when making technology, organizational and process investments in similar shared services (e.g., procurement, fleet and IS).

All these factors have been taken into account and are reflected the infrastructure investment plan submitted in this filing.

Q. Has the Company prepared an exhibit listing the electric system infrastructure investments it has planned for the period covered in this case?

A. Yes. Exhibit __ (IOP-1), Schedule 8 is a 26-page table listing all programs and projects included in the investment plan reflected in this rate case, segregated by investment category (i.e., (1) statutory or regulatory requirements; (2) damage/failure; (3) system capacity and performance; (4) asset condition; and (5) non-infrastructure (other)), and network segment (i.e., transmission, sub-transmission, or distribution) by year for the period FY11-FY14. In addition to the information set forth in Exhibit __ (IOP-1), Schedule 8, additional detail on all the infrastructure programs and projects that are reflected in this rate case are also included in the Company's 2010 Capital Investment Plan, which is being filed the same date as this rate case filing, and which is included as a work paper to our testimony.

Q. Please describe what the "Reserve" line included in several of the sheets in Exhibit __ (IOP-1), Schedule 8 represents.

A. The Reserve line, generally a negative number, is used to balance the forecasted spend for the fiscal year to the budget for the fiscal year. For example, in Exhibit__ (IOP-1), Schedule 8, Sheet 15, the budget subtotal of Transmission projects in the System Capacity and Performance category in FY11 total $54.1 million. However, the total budget for projects in that spending category is $46.3 million. The difference is the Reserve of -$7.8 million, which balances the forecast to the budget.

The Reserve is a hedge that recognizes that historically there have always been unforeseeable delays in project expenditures, projects that are cancelled as further information becomes available, and projects completed for less than estimated spend due to efficiencies. The Reserve is also used to balance for future year unidentified projects, current year walked-in projects, and projects completed in excess of the estimated cost. The Reserve can be either positive or negative.

A. <u>Statutory/Regulatory Requirements</u>

Q. Please discuss the investments the Company plans to undertake in the Statutory or Regulatory Requirements category during the period covered by this rate case.

A. Exhibit __ (IOP-1), Schedule 3 shows the Company's current and planned spending for distribution, sub-transmission, and transmission projects included in the statutory/regulatory requirements category.

As shown in Exhibit __ (IOP-1), Schedule 3, Sheet 1 of 2, the Company will spend $850 million, almost 40 percent of its FY2011- FY2014 investment budget, on projects in this category. Exhibit __ (IOP-1), Schedule 3, Sheet 2 of 2 details the breakdown of spending for statutory/regulatory purposes for the distribution, sub-transmission and transmission portions of the network by budget classification.

About $553 million (65%) of the Statutory or Regulatory Requirements spend for the FY2011- FY2014 period will be directed to the distribution network About $200 million of this amount will be required to extend overhead or underground service to new residential and commercial customers, and $124 million will be needed to purchase the transformers needed to support new and existing customers. Another $93 million is budgeted to ameliorate issues identified on the distribution system by the

Inspection and Maintenance program conducted pursuant to the PSC's 2008 Safety Order in Case 04-M-0159.[3]

The Company plans to invest $47 million (6%) of the statutory/regulatory requirements in the sub-transmission portion of the network. Nearly all of this spending will be to address issues identified through the inspection and maintenance program.

Spending to meet statutory/regulatory requirements on the transmission portion of the network is expected to increase considerably in the years ahead, when the Company will be required to spend $251 million (29%) between FY2011 and FY2014. Of this amount, $152 million is required for the Northeast Regional Reinforcement Program, needed to support the on-going Luther Forest Technology Campus project, and to solve thermal and voltage problems in the Saratoga/Glens Fall Area. An additional $53 million is directed to upgrade substations that have been newly classified at part of the bulk power system based on testing performed by the New York Independent System Operator ("NYISO"). These funds will be used to bring two substations, Clay and Porter into compliance with NPCC

[3] Order Adopting Changes to Electric Safety Standards, in Cases 04-M-0159 and 06-M-1467 ("2008 Safety Order"), issued December 15, 2008.

design, protection and operation standards for bulk power stations. The cost of these upgrades is $29 million for Clay and $24 million for Porter.

The Company will also spend over $46 million to implement its Conductor Clearance Strategy, with a program to ensure that transmission lines meet the clearance requirements established by the National Electric Safety Code ("NESC"). This work is needed to safeguard the public and Company employees as they work and travel under these over head lines, and was established in a 2005 review of the system using Aerial Laser Surveys ("ALS").

Q. Please describe some of the major projects and programs included in the Statutory or Regulatory Requirements category of the Company's infrastructure investment plan in more detail.

A. Below we provide more detailed descriptions of some of the major statutory/regulatory requirements programs and projects, segregated by portion of the electric system they address. Additional information on all of the programs and projects in this category are included in Exhibit __ (IOP-1), Schedule 8, Sheets 1-5.

Transmission

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 substation 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 the Rotterdam substation. Specific projects under this program are identified in Exhibit __ (IOP-1), Schedule 8, Sheet 5. Not doing this program would result in thermal and voltage problems under certain system conditions. This program will be funded for $7.3 million in FY11, $41.2 million in FY12, $65 million in FY13, $38.5 million in FY14, for a total of $151.9 million for the period. The estimated in-service dates for certain major plant additions under this program are reflected in the Revenue Requirements Panel Exhibit __ (RRP-6), Schedule 1, Sheet 4, lines 4, 9, and 16.[4]

115 kV Substation Bulk Power System (BPS) Upgrade. In April of 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 Niagara Mohawk substations were classified as part of the 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. This major asset program will upgrade two of our 115kV substations (Clay and Porter substations) to bulk power reliability criteria. 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 system instability and voltage collapse would occur for these contingencies. Customers in central New York will benefit from the significantly reduced vulnerability of the transmission system to these highly disruptive contingencies. These projects are budgeted at $9.9 million in FY11, $20.0 million in FY12 and $23.0

[4] Later in this testimony the Company describes the convention it uses to reflect the in-service date of investments for purposes of the revenue requirement. The testimony of the Revenue Requirements panel contains a more detailed description.

million in FY13, for a total of $52.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 5. The estimated in-service dates for major plant additions under this program are reflected in the Revenue Requirements Panel Exhibit __ (RRP-6), Schedule 1, Sheet 4, lines 11 and 13.

Conductor Clearance Strategy. The need for greater clearances was identified as a result of a 2005 review of parts of the transmission system using an innovative technology called Aerial Laser Survey ("ALS"), in which aerial surveys measure clearances with an accuracy previously unavailable except by ground inspection. This program assures that Niagara Mohawk transmission lines meet the governing NESC by increasing ground to conductor clearances in substandard spans, and follows the PSC's 2005 Safety Order in Case 04-M-0159.[5] The primary driver for this work is to ensure the safety of the public and our employees and contractors as they work and travel under the overhead lines. There is one major project within this program: the Transmission Tower Clearance project. Completion of this project is necessary to comply with the 2005 Safety Order and adhere to the NESC. The budget for this program is $1.5 million in FY11, $15.0 million in each of FY12, FY13, and FY14, for a

[5] Order Instituting Safety Standards, Case 04-M-0159, issued and effective January 5, 2005 ("2005 Safety Order").

total of $46.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 3.

Remote Terminal Unit Strategy. A Remote Terminal Unit ("RTU") is a device used to transfer operational information from a substation to an Energy Management System ("EMS") in a control center. An RTU allows for remote operation and management of the system providing benefits in incident response and recovery and thus improving performance and reliability. Modern RTUs provide the system operators the capability to more quickly and more accurately diagnose faults. In addition, protection engineers and operations engineers have access to data for analysis. And asset managers have the ability to obtain field measurements from substation data systems related to protection, power factor monitoring, phase balancing, circuit reconfiguration and load balancing. The Company's obsolete RTUs are not capable of interfacing with modern energy management systems and do not comply with NERC Recommendation 28, released in response to the August 2003 blackout.

The Transmission Remote Terminal Unit ("RTU") Strategy involves replacing obsolete monitoring and control equipment with state of the art and fully supported equipment. In addition, much of the current test equipment is no longer serviceable and operates on computer hardware and software that is no longer supported by the manufacturer. Customers will benefit from the improved reliability of the transmission system as well as the more efficient management of the grid. 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 the spread of an outage to other system components. The Company currently has three separate RTU programs within its Capital Investment Plans; these programs will address obsolete RTUs on the transmission system, and include installing over 150 new RTUs on the sub-transmission and distribution systems.

This program will be funded for $1.5 million in FY11, $2.0 million in FY12 and $1.4 million in FY13, for a total of $4.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 5.

<u>Distribution and Sub-Transmission</u>

Inspection and Maintenance Strategy and Program. The Inspection and Maintenance Strategy outlines the Company's strategy for the inspection of all electric line assets (Distribution Overhead, Underground, and Sub-Transmission line assets) to be once every five years, in conformance with the 2005 and 2008 Safety Orders. Any repair work identified as a result of the Inspection and Maintenance strategy 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 (including project bundling/outage optimization considerations).

This strategy is designed to improve the reliability and sustainability of the electric distribution network based on condition assessment, safeguard the public and employees by identifying and addressing elevated voltages locations, improve service efficiency through optimized timing of maintenance activities, and meet the requirements of the PSC's 2005 and 2008 Safety Orders. The Distribution strategy is funded at $17.4 million in FY11, $29 million in FY12, $25.1 million in FY13, and $22.1 million in FY14, for a total of $93.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 1. Different project stages under the

Distribution portion of this program will be closing 3 months following the expenditure of the funds. The Sub–transmission strategy is funded at $9.6 million in FY11, $10 million in FY12, $11 million in FY13, and $11.5 million in FY14, for a total of $42.1 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 3.

B. Damage/Failure

Q. Please discuss the investments the Company plans to undertake in the Damage/Failure category during the period covered by this rate case.

A. Failed and damaged equipment caused about 40 percent of customer interruptions between 2006 and 2009.[6] With this in mind, the Company's investment plan includes $133 million over the period FY11 to FY14 to replace equipment that unexpectedly fails or becomes damaged. Exhibit __ (IOP-1), Schedule 4, shows the Company's current and planned spending to repair failed or damaged equipment on the distribution, transmission and sub-transmission portions of the network.

[6] Deteriorated equipment contributed to over 25 percent of customer interruptions during this period while lightning, motor vehicle accidents, and vandalism were responsible for another 16 percent.

More than two thirds of this spending ($90 million) is required to address issues along the distribution portion of the network due to failed equipment or damage caused by severe weather.

The Company expects to spend an additional $27 million to replace equipment that based on experience may fail or becomes damaged along the transmission portion of the network. Almost half of these funds have been designated to replace rotting wood transmission poles that are deemed to be beyond restoration so as to ensure compliance with the National Electric Safety Code and in accordance with the Commission's 2005 and 2008 Safety Orders.

The Company expects that required spending to replace failed or damaged equipment will be relatively flat over the rate plan period. The flatness of this budget is also dependent on implementing the investments identified in the System Capacity and Performance and Asset Condition categories (described later). Without the investments in those categories it is anticipated that the projected spending required to replace failed and damaged equipment would be higher.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the Damage/Failure (D/F) category.

A. Below we provide a description of major projects and programs in this category, segregated by portion of the electric system they address. Detailed information on these programs and projects is included in Exhibit __ (IOP-1), Schedule 8, Sheets 6-7.

Transmission

Apart from a five-year budgetary reserve of $11.5 million added for remediation of unforeseeable failures based on historical spending levels, there are three major transmission programs associated with the Damage/Failure category. All three of these projects are driven by field inspection results. The Company follows a number of standard industry practices for the inspection of its overhead line assets. These include five year ground-level foot patrols, annual aerial infra-red (IR) inspections, ground level inspections for wood poles, footer inspections for steel structures and specific comprehensive inspections of lines with reliability issues. There are currently three programs employed to address the results of these inspections. First, the New York Inspection Projects which will address all the urgent condition issues that arise from the foot patrols, IR inspections, footer inspections and comprehensive inspections. Second, the Wood Pole Strategy will address all the issues on wood poles identified by the ground level inspections (Osmose Inspections). Finally, the Overhead Line Refurbishment Strategy will address all the long-term i.e. non-urgent condition issues identified through inspection. The current Steel Tower strategy will be phased-out during FY12 and be replaced by the long-term overhead line refurbishment strategy (described later in the Asset Condition section). Different project stages under this program will be closing 6 months following the expenditure of the funds.

NY Inspection Projects. This program assures that both steel tower and wood pole transmission lines meet the governing NESC standards by replacing hardware, wood poles, and structure components that no longer meet the governing code requirements. This follows standard industry practice and the Commission's 2005 Safety Order 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.). This program will be funded for $0.5 million in FY11, $1 million in FY12 and FY13 and $3 million in FY14, for a total of $5.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 6. Different project stages under this program will be closing 6 months following the expenditure of the funds.

Wood Pole Strategy. Under this program, wood poles that are either priority rejects or reject poles (as classified following a ground line inspection), as well as those damaged by woodpecker activity, will be replaced. This program targets wood poles 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," that is, deteriorated wood poles from such things as woodpecker damage, insect damage, or rotting are included. The maintenance of appropriate public safety level by assuring that transmission wood structures continue to meet the governing NESC standards is the driver for this program. Implementation of this program is necessary to conform to the Safety Orders and adhere to the NESC. The Wood Pole Strategy will be funded for $1.8 million in FY11, $1.5 million in FY12, $1.6 million in FY13, and $3.0 million in FY14, for a total of $7.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 7. The increasing amount in the later years reflects a forecast increase in the number of priority rejects that is expected in coming years. Different project stages under this program will be closing 6 months following the expenditure of the funds.

<u>Sub-Transmission and Distribution</u>

Damage/Failure (D/F) programs and projects also cover sub-transmission and distribution substation, overhead and underground line construction and replacement resulting from vehicle accidents, weather (where a storm project is not required), vandalism, and asset failure. Projects are budgeted based on historical trends. This category also includes Level 1 Prioritized work identified through Inspection and Maintenance. The Company establishes a budget reserve for specific projects required to address failed equipment that arise during the year and cost more than $100,000. These reserves are based on historical calculations for specific projects within the category. The size and volume of damage/failures drives the spending within these projects. The infrastructure investment plan includes a D/F budget for the sub-transmission system of $3.6 million in FY11, $3.8 million in FY 12, $3.9 million FY13 and $4.0 million in FY14, for a total of $15.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 6. For the distribution system, funding for this D/F work is budgeted at $20.9 million in FY11, $22.1 million in FY 12, in $22.9 million FY13 and $23.7 million in FY14, for a total of $89.7 million for the period. , as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 6.

C. <u>System Capacity and Performance</u>

Q. Please discuss the investments the Company plans to undertake in the System Capacity and Performance category during the period covered by this rate case.

A. The Company plans to spend $502 million, 23 percent of the total FY2011- FY2014 investment budget, on System Capacity and Performance projects, as reflected in Exhibit __ (IOP-1), Schedule 5. It provides breakdowns of spending for System Capacity and Performance for the distribution, sub-transmission, and transmission portions of the network and by Program.

Approximately $228 million will be directed to the distribution portion of the network for projects required to address capacity constraints and correct impending reliability issues. Of this amount, $126 million will be required to ensure the distribution network can accommodate anticipated load growth without compromising reliability. This includes replacing line transformers in areas where capacity is or will soon be constrained and "Planning Criteria" projects to ensure other parts of the distribution network have sufficient capacity to meet the anticipated load. The analysis that developed the load forecast used in the capacity planning process incorporates the impacts of energy efficiency programs and distributed generation continuing at historic rates.

The Company's system planning group has also recently begun to review the list of prospective "load growth" projects to identify locations where the Company's targeted demand response or energy efficiency programs might either defer or obviate the need for an expansion project.

Approximately $95 million of funds in the System Capacity and Performance category for the distribution network will be used to up-grade or replace assets in the Company's distribution substations. These projects are key to the Company's plan to maintain and improve reliability because problems in substations can interrupt a large number of customers given the up-stream position of substations on the distribution network.

In order to better monitor the performance of distribution substations, the Company will spend approximately $21 million to replace obsolete Remote Terminal Units ("RTU") to transfer data to the energy management system in the control center

In addition to specific projects; i.e., those $100,000 or greater, required to assure the network meets system planning criteria, the Company also budgets for work less than $100,000 under a Distribution Reliability Blanket Project established for each operating division. Some examples of the type of work that would come under the Distribution Reliability Blanket include installing sectionalizing switches, replacing conductor, correcting for low voltage, minor primary side tap rebuilds, and relocating facilities in response to repeated motor vehicle accidents. The Company projects that nearly $30 million will be required between FY11 and FY14 to fund this blanket.

An additional $11 million has been directed to perform the work identified in annual engineering reliability reviews ("ERRs") on specific feeders in response to reliability issues. The feeders targeted for review include many of those tagged as 'worst performing feeders' in the Company's annual reliability report.

The Company will also spend $27 million on distribution line reclosers that will help to isolate permanent faults on the overhead distribution system to minimize the impact of a fault on customers. Another $8 million will be used to address pockets of poor performance where customers have been subject to frequent interruptions due to recurring problems with on the network. The range of potential work on pockets of poor performance will depend on the problems that are identified through an engineering reliability review.

The Company will spend $49 million to address system capacity and performance issues on the sub-transmission system. More than half of this spending will be required to ensure that the sub-transmission network meets the Company's planning criteria. Much of this spending will be directed toward re-conductoring portions of the sub-transmission system especially in the Kensington area and in the vicinity of the former Huntley Station in Tonawanda. The Company will also direct funds to support new large customers, including the Buffalo Niagara Medical Campus, and to automate portions of the sub-transmission system

The Company will spend $225 million from FY11-FY14 in the System Capacity and Performance category on the transmission system. Almost half of that amount is designated for nearly twenty projects to ensure that the non-Bulk portion of the transmission system complies with the Company's N-1-1- Reliability Planning criteria.

Another $102 million of these funds will be required to fund projects in the Frontier, Genesee, and Southwest regions needed to mitigate risks to the bulk power system following the retirement of 355 MWs in 2007 at the Huntley Power Station in Tonawanda. Capacitor banks installed at Huntley will mitigate most immediate system concerns. The Company will need to construct a new substation in Tonawanda and relocate six circuits to the new station in order to mitigate the need for load shedding in the event of a severe fault.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the System Capacity and Performance category in more detail.

A. Below we provide a description of some major projects and programs in this category, segregated by portion of the electric system they address. Additional information on all of the programs and projects in this category are included in Exhibit __ (IOP-1), Schedule 8, Sheets 8-15. In addition, there are three additional projects included in the Company's investment plans that are not described in this section. These are described in greater detail in the section entitled Additional Projects, later in our testimony.

Transmission

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 retired Huntley Generating Station in Western New York. These expenditures are driven by the closure of generation at Huntley and the present system conditions and minor load growth expectations are needed before the summer of 2012 in order to avoid severe thermal and voltage problems that would impact system security and reliability. Transmission system reliability improvements will develop through the implementation of the permanent solutions. Prior to 2012, the capacitor banks recently 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 until the upgrades are completed. Currently, there are two projects directly included in the program: the construction of the Tonawanda station, and the relocation of the six circuits that will in the future terminate at the new station. In addition to the Tonawanda projects, the refurbishment of the Huntley 230kV Station is associated with this program. This program (excluding the Huntley station) will be funded for $29.3 million in FY11, $54.3 million in FY12, $12.3 million in FY13 and $5.7 million in FY14, for a total of $101.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. The estimated in-service date for the Tonawanda Station under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 7. Other project stages under this program will be closing from 6-12 months following the expenditure of the funds.

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 NY/Canada border east to Mortimer Station and south to the Pennsylvania border. The reinforcements are needed to ensure adherence to reliability standards by strengthening the transmission network. Completion of this strategy will substantially reduce the exposure of customers to service interruptions. Generation that currently must be run at times for reliability purposes will no longer be required, avoiding future costs of dispatching the generation out of NYISO merit order. In addition some capability to accommodate new or expanding load will be added to the system. This program will be funded for $11.6 million in FY11, $29.8 million in FY12, $33.3 million in FY13 and $23.1 million in FY14, for a total of $97.8 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 15. The estimated in-service date for the

Construct Southwest Station project under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 12. Other project stages under this program will be closing from 6-12 months following the expenditure of the funds.

Other System Capacity and Performance. There are eleven separate projects with spend greater than $2 million each included in the "Other System Capacity and Performance" program, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 14. These projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of our customers. Projects in this category are intended to prevent the degradation of equipment service lives due to thermal stress and to provide appropriate degrees of system reconfiguration flexibility to limit adverse reliability impacts of large contingencies. The Syracuse area re-conductoring prospective project 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. This program will help avoid thermal overloads on the 115 kV system during contingency conditions. The program scope includes the following projects: Re-conductoring approximately 6.4 miles of the Yahnundasis–Porter 115kV circuit #3: Re-conductoring two separate sections (one 6.8 miles, the other 6.1 miles) of the Clay–Teall 115kV circuit #10; and Re-conductoring 10.2 miles of Clay–Dewitt 115kV circuit #3. Planned investment for all the projects in the “Other System Capacity and Performance” program total $5.8 million in FY11, $7.3 million in FY12, $10 million in FY13 and $21 million in FY14, for a total of $44.1 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 14. Different project stages under this program will be closing from 6-12 months following the expenditure of the funds.

Sub-Transmission

23kV Upgrades Associated with Buffalo Niagara Medical Campus. The Buffalo Niagara Medical Campus is a collection of medical facilities in the downtown Buffalo, NY area that are planning major capacity increases. Combined, the Company has received requests for an additional 16.5MVA of new load in these areas. This additional load will overload the 23kV cable group supporting the area. To provide the necessary capacity to meet these customer requests, an additional cable group of four 23kV cables will be installed. To accommodate these additional circuits an underground conduit system is required as well as an additional bay of breakers at the Elm Street substation. The project is on a fast track to meet the customers’ expansion plans. Project costs are budgeted at $7.3 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages under this program will be closing from 6-12 months following the expenditure of the funds.

23kV Cable Upgrades Huntley to Buffalo Station 24. This project will replace and upgrade four 23kV underground sub-transmission cables from Huntley substation supplying Buffalo Station 24. This group of cables is expected to be loaded beyond normal ratings during peak load periods as early as the summer of 2010. These improvements will also address potential contingency overloads on the same cables as post contingency loading could exceed emergency ratings by summer 2010. The project is in the conceptual engineering phase. Construction is expected to begin in late 2010 with an expected completion date of summer 2012. The project is budgeted at $0.2 million in FY11, $1.0 million in FY12, and $6.2 million in FY13, for a total of $7.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds

23kV Cable Upgrades Huntley to Buffalo Station 52. This project will replace and upgrade one 23kV underground sub-transmission cable from Huntley substation supplying Buffalo Station 52. This cable is expected to be loaded beyond normal ratings during peak load periods as early as the summer of 2010. These improvements will address potential contingency overload on the same cable as post contingency loading could exceed emergency ratings by summer 2010. The project is in the conceptual engineering phase. Construction is expected to begin in late 2010 with an expected completion date of summer 2012. The project is budgeted at $0.2 million in FY11, $1.0 million in FY12, and $1.2 million in FY13, for a total of $2.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Upgrade Bethlehem – Avenue A #10 Line. This project will upgrade 1.8 miles of 34.5kV underground sub-transmission including new ducts and cable to provide load relief to the #10 line which is forecasted to reach its normal rating by the summer of 2011 and which could exceed its emergency ratings under contingency loading conditions. Upgrade of this cable will maintain existing reliability performance levels and provide additional area capacity for load growth. The project is in the conceptual engineering phase. Construction is expected to begin in late 2011 with an expected completion date of spring 2013. The project is budgeted at $0.3 million in FY12, and $2.0 million in FY12, for a total of $2.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13.

Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Sub-Transmission Line Sectionalizing. A program is being developed to increase the sectionalizing capability of radial sub-transmission lines to better isolate faulted sections of lines thus facilitating the rapid restoration of customers on sections that are not adversely impacted.. The program is expected to extend over many years. Budgets have been forecasted based on conceptual expectations. This project is budgeted at $0.5 million in FY11, $1.0 million in FY12, $2.0 million in FY13, and $4.0 million in FY14, for a total of $7.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Distribution

Pockets of Poor Performance Strategy. The intent of this strategy is to identify subsections of feeders (typically at the line fuse level) experiencing measurably more frequent customer interruptions than the remainder of the feeder. Typically, these identified areas are known as "pockets of poor performance." The reliability levels targeted by 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.

Once these 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 (e.g., tree trimming, repairing equipment, grounding and bonding) and/or line reconductoring. The Pockets of Poor Performance Strategy is level-funded at $2.1 million per year for FY11-FY14, for a total of $8.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12.

Distribution Line Transformer Strategy. This is a "predictive approach" to mitigate unplanned outage/failure risks due to overloading and asset condition. There are approximately 442,000 transformers on Niagara Mohawk's distribution system. Transformer loading is reviewed annually using reports generated by the Company's GIS system. Transformers with calculated demands exceeding load limits specified in the applicable Construction Standard are investigated and overloaded installations are addressed by replacement with a larger unit or load is relieved via installation of a second transformer. The physical condition of distribution line transformers is evaluated on a five-year cycle as part of the Overhead and Underground Inspection and Maintenance Strategy. Poor condition units are replaced based on inspection results. The Strategy is in addition to replacements that are performed during customer-service upgrades, public requirements projects, and system-improvement projects. The main benefit of this strategy is the maximization of asset utilization, and sustained reliability performance. The Distribution Line Transformer strategy is funded at $4.5 million in FY11, $4.6 million in FY12, $7.6 million in FY13 and $9.6 million in FY14, for a total of $26.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 8. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Feeder Hardening Strategy. The Feeder Hardening strategy and program identifies 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 state regulatory targets. Feeders in this program undergo replacement of deteriorated equipment, installation of lightning arresters and animal guards and correction of non-standard grounding and bonding issues. FY11 is the year last feeder hardening will be utilized in NY. The Inspection and Maintenance Strategy incorporates the components of the Feeder Hardening Strategy after FY11. The Feeder Hardening strategy is funded at $3.0 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 9. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Distribution Line Recloser Strategy. The recloser application strategy is a reliability-focused strategy to install line reclosers on overhead distribution lines. Line reclosers are used to isolate permanent faults on the distribution system and minimize exposure of a fault to customers. 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. The benefits of this program are reduced outage duration and outage frequency. The Distribution Line Recloser Strategy is funded at $5 million in FY11, $6 million in FY12, $6 million in FY13, and $10 million in FY14, for a total of $27 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Distribution Reliability Blanket. In addition to specific projects; i.e., those $100,000 or greater, the Company also budgets for work less than $100,000 under a Distribution Reliability Blanket Project established for each operating division. The amount of funding in each divisional blanket project is reviewed, and approved, each year based on the results of the previous annual reliability review, historical trends in the volume of work required as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The blankets also provide local field engineering in each operating division with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. These blanket projects are budgeted at $6.6 million in FY11, $7.2 million in FY12, $7.8 million in FY13, and $8.3 million in FY14, for a total of $29.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 8. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Planning Criteria Projects. An annual capacity planning assessment is conducted to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur. The capacity planning process is summarized by the following tasks:

- Review of historic loading on each sub-transmission line, substation transformer, and distribution feeder.
- Weather adjustment of recent actual peak loads,
- Econometric forecast of future peak demand growth,
- Analysis of forecasted peak loads vis-à-vis equipment ratings,
- Consideration of system flexibility in response to various contingency scenarios, and
- Development of system enhancement project proposals.

Individual project proposals are identified to address planning criteria violations identified. At a conceptual level, these project proposals are prioritized and submitted for inclusion in future capital work plans. Projects in the load relief program are typically new or upgraded substations and distribution feeder mainline circuits. Other projects in this program are designed to improve the switching flexibility of the network, improve voltage profile, or to release capacity via improved reactive power support.

Some of the most significant planning criteria projects include:

Sycaway – Add 13.2kV Switchgear. The Sycaway substation is a 115-13.2kV substation in Brunswick serves approximately 4600 customers. The existing transformer and local feeders are forecasted loaded above their rating during summer peak periods. The substation is being expanded to add a second transformer, 13.2kV switchgear, substation capacitor banks and two additional 13.2kV feeders to serve area loads and provide improved operational flexibility to respond to various contingency with feeder switching. The project is currently in the final engineering stage. Construction is expected to complete in March 2011 with project closure in September 2011. This portion of the project is budgeted at $2.1 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

Swann Road TB2 Replacement. Swann Rd is a 115 -13.2kv two transformer substation in Lewiston. The existing transformer bank (TB) #2 is in poor condition and will be replaced with a new 25MVA unit. The project is expected to be completed in the spring of 2011 and it budgeted at $2.2 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

Inman Rd - Add 13.2kV Switchgear. Inman Rd is a 115-13.2kV substation in Niskayuna. There are loading and voltage concerns on nearby distribution feeders served from the Rosa and Watt Street substations. The addition of a second 33MVA transformer, 13.2kV switchgear, substation capacitor bank and two new 13.2kV feeders will provide additional area capacity to relieve area facilities and improve customer service. The project is currently in preliminary engineering. Construction is expected to begin in summer of 2011 and complete by March of 2012. The project is budgeted at $1.0 million in FY11 and $2.2 million in FY12, for a total of $3.2 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

***Frankhauser – Add 13.2kV Switchgear*.** This project proposes the installation of a new 115-13.2kV substation on Company owned land off Frankhauser Rd in Amherst. The primary driver of this project is to maintain reliability of the area and provide load relief for five area feeders that are expected to reach or exceed their summer ratings by 2012. In addition seven area substation transformers are at risk of exceeding their emergency ratings for a single contingency if load were not shed at peak periods. The plan to resolve these issues is to install this new substation with a 115-13.2kV 40MVA transformer, 13.2kV switchgear, substation capacitor bank, and four 13.2kV feeders. This project funds the 13.2kV substation additions associated with this plan. The project is currently in preliminary engineering. Construction is expected to begin in spring of

2011 and complete by March of 2012. The project is budgeted at $0.3 million in FY11 and $2.0 million in FY12, for a total of $2.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

West Albion Transformer Addition. The West Albion substation is 34.5-13.2kV substation located in Albion. The existing transformer is forecasted to be overloaded and a second 5.3MVA transformer, regulators and additional 13.2kV feeder will be added to the substation to provide additional capacity to relieve the overloaded facilities. This project funds the associated substation additions. The project is currently in conceptual engineering phase. Construction is expected to begin in spring of 2011 and complete by March of 2012. The project is budgeted at $0.5 million in FY11 and $2.5 million in FY12, for a total of $3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 11.

Starr Road Second Transformer. Starr Road is a 115-13.2kV substation in Cortland. It serves 22MVA of area load from a single 25MVA transformer. The limited field ties from other substations cannot carry all of the load of the station in the event of a transformer contingency. This may result in customer outages up to 24 hours in duration while a mobile substation is installed under emergency conditions. This project proposes to install a second 25MVA transformer at the substation as well as a 13.2kV tie switch inside the substation. The project is currently in the conceptual engineering phase. Construction is expected to begin in spring of 2012 and complete by March of 2013. The project is budgeted at $1.9 million in FY12 and $0.4 million in FY13, for a total of $2.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 11.

Ogden Brook – Installation of a 13.2kV Switchgear. The Ogden Brook substation is a 115-13.2kV serving approximately 3000 customers in the Glens Falls area via a single 22MVA transformer. The transformer is forecasted to be overloaded by the summer of 2013. This project proposes the addition of a second transformer, 13.2kV bus, substation capacitor and a new 13.2kV feeder to provide needed capacity to the area to reliably serve these customers. The project is currently in conceptual engineering phase. Construction is expected to begin in autumn 2010 and be complete by March of 2013. The project is budgeted at $0.25 million in FY11, $2.0 million in FY12 and $2.8 million in FY13, for a total of $5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 11.

Ballston – Installation of a 13.2kV Switchgear. The Ballston substation is a 115-13.2kV substation in Ballston Spa. The single 22MVA transformer is heavily loaded and is currently being managed via load transfers among neighboring facilities. This project proposes to increase the capacity of the substation with the addition of a second transformer, switchgear and additional feeders. The project is early in the conceptual engineering phase. Construction is expected to begin until spring 2012 with a forecasted in service date around March 2014. The project is budgeted at $2.9 million in FY13 and $0.7 million in FY14, for a total of $3.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12.

North Syracuse Capacity Increase. The North Syracuse study area encompasses the Towns of Clay, Cicero, Lysander and Salina. The area is loaded to 335MVA and serves approximately 67,000 customers. In 2008 two feeders were loaded beyond their summer normal rating and six substation transformers were at risk of contingency overload that would require load shedding at peak load periods. This project will add needed capacity to the area with the addition of a new 115-13.2kV substation with a 40MVA transformer, substation capacitor bank and switchgear supplying 5 new distribution feeders. Completion of this project will enhance customer reliability and will provide area capacity to support the continued load growth expected in the area. The project is in the preliminary engineering phase. Construction is expected to begin in autumn 2010 with a forecasted in service date around September 2012.

The project is budgeted at $0.79 million in FY11, $2.3 million in FY12 and $0.1 million in FY13, for a total of $3.19 million for the period.

Distribution Load Relief Blanket. In addition to specific projects; i.e., those $100,000 or greater, required to realign the network with system planning criteria, the Company also budgets for work less than $100,000 under a Distribution Load Relief Blanket Project established for each operating division. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The amount of funding in each divisional blanket project is reviewed, and approved, each year based on the results of the previous annual capacity planning review, historical trends in the volume of work required as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. The blankets also provide local field engineering in each operating division with the control accounts to facilitate timely resolution of system and equipment loading issues. These blanket projects are utilized to respond to issues such as overloaded sections of wire/cable or step-down transformers, the installation of feeder voltage regulators and capacitors, as well as minor work necessary to facilitate the reallocation of load on existing circuits. These blanket projects are budgeted at $1.1 million in FY11, $1.1 million in FY12, $1.2

million in FY13 and $1.2 million in FY14, for a total of $4.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12.

Replacement RTU Program – Substations. This is one of the three RTU projects mentioned earlier in the testimony. This program will replace RTU's where existing RTU's have become obsolete and unsupported by the manufacturer. Replacement of these devices will ensure reliable operation of the electric system. The program is expected to extend over many years. Replacement candidates for the next 2 years are in the engineering phase and construction plans are prepared. Future year budgets have been forecasted based on conceptual expectations over the five year horizon. Construction is expected to begin summer of 2010. This project is budgeted at $1.8 million in FY11, $1.8 million in FY12, $1.8 million in FY13 and $2.0 million in FY14, for a total of $7.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12. Different project stages will close throughout the program life, with closing occurring 9 months following the expenditure of the funds.

New Substation RTU Program. This also is one of the three RTU projects mentioned earlier in the testimony. Currently over 150 out of the 441 distribution and subtransmission substations require installation of RTU's. 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. Substations equipped with RTU's and subsequent communication to the EMS system can provide up to a 15 percent reduction in average customer outage duration (CAIDI) when compared with a similar feeder that is not equipped with and RTU to transfer information to the EMS capabilities. Based upon historical cost of similar projects, the strategy is funded at $2.5 million in FY11, $3.0 million in FY12, $3.0 million in FY13, and $4.0 million in FY14, for a total of $12.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12. Different project stages will close throughout the program life, with closing occurring 9 months following the expenditure of the funds.

D. Asset Condition

Q. Please discuss the investments the Company plans to undertake in the Asset Condition category during the period covered by this rate case.

A. Exhibit __ (IOP-1), Schedule 6, Sheet 1 of 4 shows the Company's investment plan levels for projects required to address Asset Condition issues. Exhibit __ (IOP-1), Schedule 6, Sheet 4 of 4 details the breakdown of spending for Asset Condition for the transmission portions of the network. Exhibit_ (IOP-1), Schedule 6, Sheet 2 of 4 details the breakdown of spending for Asset Condition for the distribution portion of the network by strategy. Exhibit__ (IOP-1), Schedule 6, Sheet 3 of 4 details Asset Condition Spending for the sub-transmission potion of the network by strategy.

The Company expects to spend $690 million, nearly 32 percent of its FY11-FY14 investment budget, to improve the condition of deteriorated assets.

Over 60 percent of this spending ($430 million) is required to improve and sustain the condition of the transmission system. Approximately $198 million of this spending will be required to refurbish overhead lines. This spending will be the initial installment of a 25 year program to replace or refurbish steel towers, wood poles and re-conductor several transmission lines to assure the system remains in compliance with the 2005 Safety Order and the National Electric Safety Code. Another $139 million will be required to rebuild transmission substations in Gardenville, Dunkirk, Lockport, Lighthouse Hill and Rome. The planned replacement of these stations reduces the likelihood of an unplanned failure which could lead to long interruptions of the transmission system and the interruption of service to large numbers of customers. The Company also is also planning to direct $25 million to replace 39 transformers that have been designated as “high priority” based on their asset condition. An additional $23 million will be used to replace problematic circuit breakers in order to reduce the risk of in-service failure that could lead to a lengthy interruption on the transmission system and significant customer interruptions.

The Company’s investment plan will also direct $148 million to replace assets on the distribution portion of its network based on asset condition. As shown in Exhibit __ (IOP-1), Schedule 6, Sheet 2, two thirds of these funds will be used to replace equipment in substations. Close to $59 million will be used to replace or rebuild the Indoor 23-4kV Substations that were built in the 1930s and 1940s that now pose safety, capacity, and reliability issues. The Company will spend another $17 million to replace substation circuit breakers and to remove circuit breakers that are obsolete or do not operate properly and undermine reliability. Another $14 million will be used to replace the metalclad switchgear in several distribution substations: Altamont, Market Hill, North Troy and Oneida. This equipment is in poor condition, and when this class of switchgear fails, it generally impacts the entire bus and interrupts service to many customers. The Company plans to spend $16 million to replace underground cable and another $8 million to improve networks in urban areas to reduce reliability concerns.

As shown in Exhibit __ (IOP-1), Schedule 6, Sheet 3, the Company is also planning to spend $112 million to improve the condition of assets along the sub-transmission network. Most of this spending will be to replace towers, line, and underground cable. Over 20 percent of these funds will be used to replace equipment in substations.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the Asset Condition category.

A. Below we provide a description of major projects and programs in this category, segregated by portion of the electric system they address. Details of individual programs and projects is included in Exhibit __ (IOP-1), Schedule 8, Sheets 16-25.

<u>Transmission</u>

3A/3B Tower Strategy. In October 2003 Structure 347 on the Edic-New Scotland 14 line, a type 3A tower, failed. Two previous failures occurred on type 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 of this strategy 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. 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. The scope of this program is being developed with consideration of the overall risks to public safety as the primary driver with improved reliability a secondary benefit. The Company has limited the program to those towers which pose the greatest risk to public safety in order to reduce the costs of the programs. The two projects included within this program are: “Leads - Pleasant Valley 91/92 tower reinforcement” and “New Scotland – Leads 93/94 tower reinforcement.” Implementing the program will reduce the risk of additional failures of the same type of towers in the future. This program will be funded for $0.05 million in FY12, $0.15 million in FY13, and $6.1 million in FY14, for a total of $6.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 22. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Battery Strategy. Battery and charger systems are critical components that are needed to insure full substation operational capability during both normal and abnormal system conditions. A battery system that does not perform adequately could result in serious reliability consequences. There are three different projects within this program, the largest of which ("Battery Replacement Strategy Co36TxT") is funded for $1.2 million per year in FY11 and FY12, and $0.6 million per year in FY13 and FY14, for a total of $3.7 million for the period, as indicated in Exhibit __(IOP-1), Schedule 8, Sheet 22. Different project stages will close throughout the program life, with closing occurring 12 months following expenditure of the funds.

Circuit Breaker Replacement Strategy. The circuit breaker replacement strategy will address problematic circuit breakers on the Company's system. Circuit breakers play a key role in system performance, particularly for fault clearance, and the strategy is necessary to address problem circuit breakers and to prevent failures and unplanned outages. This strategy involves the purchase and installation of 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 conditions warrant, the Company will replace disconnects, control cable and other equipment associated with these circuit breakers. The planned replacement of these circuit breakers reduces the likelihood of an unplanned failure which can lead to lengthy interruptions of the transmission system as well as significant customer outages. The program would also reduce the potential for catastrophic failures that pose safety risks, as well as the risk of damage to surrounding equipment. The program will be funded for $0.1 million in FY11, $1.1 million in FY12, $7.3 in FY13, and $14.5 million in FY014, for a total of $23 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 22. The estimated in-service date for the Circuit Breaker Replacement (priority 4) project under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 7. Other project stages will close throughout the program life, with closing occurring 12 months following expenditure of the funds.

Overhead Line Refurbishment Program. The Company has over 5,800 circuit miles of Transmission overhead lines in upstate New

York 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 as required by the Commission's 2005 Safety Order. Secondly the program will improve the reliability of the aging transmission system by rebuilding the worst performing lines before they become unacceptably unreliable.

The overhead line refurbishment program assures that the Company's transmission lines meet the governing NESC standards. 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. Refurbishment projects have been selected based upon six factors;

i) five-year average reliability statistics as published in the Transmission Network performance Report or any circuits that appear in the external SGS Statistical Services benchmarking list of worst performing 100 circuits

ii) condition as determined by field inspection, testing and analysis

iii) age distribution figures for overhead line assets show an aged 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

iv) whether the line consists of steel or wood structures

v) 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 factor in additional considerations, such as outage availability, bundling to create economic packages of work, interaction with other strategies and projects, etc. In the early years the program emphasizes the worst performing circuits, typically 115kV circuits and aims to move transmission in New York to a longer-term (25+ years), systematic refurbishment approach for all overhead lines.

The following table IOP-1 lists overhead line refurbishment projects that are either underway or have been initiated. Along with the list of circuits we have highlighted their current and previous rank in terms of least reliable. Seven out of the top ten circuits are included on the list and 16 out of the top 40.

Table IOP-1
Overhead Line refurbishments for the period FY10/11 – FY13/14

Circuit ID	Circuit Name	2009 Rank	2008 Rank
T1260	Gardenville-Dunkirk 141	2	7
T1270	Gardenville – Dunkirk 142	Double circuit efficiency	
T1530	Lockport - Mortimer 111	3	1
T1280	Gardenville – Homer Hill 152	4	3
T1950	Gardenville – Homer Hill 151	Double circuit efficiency	
T1540	Lockport - Mortimer 113	18	24
T1550	Lockport – Mortimer 114	1	7
T1510	Lockport – Batavia 112	6	5
T5770	Spier – West 9 (also a System Capacity project)	5	9
T3340	Taylorville – Mosier 7	7	8
T1160	Falconer – Homer Hill 153	34	20
T1170	Falconer – Homer Hill 154	16	17
T1340	Homer Hill – Bennett Road 157	11	29
T1660	Niagara – Gardenville 180	31	13
T1780	Niagara – Gardenville 182	32	42
T3320	Taylorville – Boonville 5	15	18
T3330	Taylorville – Boonville 6	Double circuit efficiency	
T1860	Pannell – Geneva 4 / 4A	14	39
T4210	Porter – Rotterdam 31 (bulk)	19	19

Replacing deteriorated assets ahead of failure to maintain or improve reliability for customers is the objective for the overhead line refurbishment program. There are 15 projects over $2 million within this category including as discussed 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. This program will be funded for $20.2 million in FY11, $32.4 million in FY12, $53.4 million in FY13 and $92 million in FY14, for a total of approximately $198 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Relay Replacement Strategy and Program. This strategy and program 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. Niagara Mohawk's transmission system is protected by approximately 8,000 relays. Approximately 6,500 in-service relays are electro-mechanical or solid state types. Many electro-mechanical and solid state relays are at or near their end-of-life. A replacement plan targeting the worst performing or obsolete relay families is planned to address this. Protective relays that are functioning properly are essential to a rapid isolation of faults on the system, protecting customers from outages and protecting equipment from damage. The new relays will yield additional operational data that has not been available previously, which will help identify the root causes of system failures and make it easier to prevent reoccurrences. This program will be funded for $50,000 in FY11, $1 million in FY12, $3.8 million in FY13, and $6.5 million, for a total of $11.35 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. Different project stages will close throughout the program life, with closing occurring 12 months following completion of the work.

RHE Breaker Replacement. This program includes the replacement of Federal Pacific oil circuit breakers (manufacturer's type code RHE). Due to their key function, the reliability of these circuit breakers is viewed as critical. 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. 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. The planned replacement of these circuit breakers reduces the likelihood of an in-service failure. The two projects within this program are “Lighthouse Hill” and “Oneida.” This program will be funded for $0.1 million in FY11, $0.3 million in FY12 and $0.5 million in FY13, for a total of $0.93 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24.

Shield Wire Strategy and Program. The shield wire is a critical element of a high voltage transmission line. 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. 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 mechanical forces in the longitudinal direction. These forces, which can also compromise shield wire protection, 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 shield wire system will help minimize structural related outages. A dropped shield wire that goes unnoticed (no outage) creates a major safety concern to the public. The Shield Wire Strategy and Program involves replacement of a significant amount of shield wire on the overhead transmission system. In some instances OPGW ("optical fiber ground wire") will be used during shield wire or overhead line refurbishment projects. With the increasing need for communication bandwidth for SCADA, security and future SmartGrid applications, leveraging existing overhead line infrastructure to provide these communication routes is beneficial. The targeted assets are the shield wire on more than 400 miles of 115kV transmission lines or approximately seven percent of the total 115kV system. In addition to the safety issues, the program is targeting reliability improvements of the 115kV transmission system by reducing the total duration of sustained outages by over 2,000 minutes/year. The largest project in this program is the Gardenville-Homer 151/152 project. This program will be funded for $8.2 million in FY11 and $7.2 million in FY12, for a total of approximately $15.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of funds.

Substation Rebuild Projects. There are six stations under study for either upgrades or rebuilds to better meet current and future needs of the transmission system and its users: Gardenville (230/115kV), Dunkirk (230/115kV), Rome (115kV), Lockport (115/12kV), Lighthouse Hill (115/12kV) and Rotterdam (230kV, 115kV, 69kV, 34.5kV and 13.2kV).

At this stage of planning, the six projects are anticipated to cost slightly more than $139 million in total. Details for these projects are included in Exhibit __ (IOP-1), Schedule 8, Sheet 24.

- **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. The estimated in-service date for this project is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, line 6.

- **Dunkirk:** The station is a 230/115kV station located south of Buffalo, and connected to 522MW of generation owned by NRG. The generation at Dunkirk was owned by Niagara Mohawk but sold to 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 cable issues. Complete replacement of control cables is not possible due to space constraints in shared areas.
- **Rome:** The station was constructed in the early 1920s. It has received several reconfigurations over the years with the current 115kV to 13.2kV dual bus being built in the early 1970s. The 115kV system at the 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 at the site that produced natural gas which ultimately contaminated the site. There are multiple asset condition issues affecting the station including the 115kV disconnects being in poor condition and often failing while being operated. The 115kV

instrument transformers have weakened foundations, batteries and chargers have failed during bus outages, the control house has asbestos and deteriorated windows and doors and inadequate lighting, and the steel structure for the North bus is heavily corroded with degraded footings.

- **Lockport**: The station is a major 115kV transmission station with thirteen 115 kV transmission lines tying through the east and west bus sections. The overall condition of the station yard and control room is poor. This station was originally part of the 25 cycle system dating back to the 1910s. There is still some 25 cycle oil filled equipment which needs to be drained of oil and removed to avoid possible environmental problems or safety issues. The structures are severely rusted and in need of painting before steel is compromised. Support columns and breaker foundations are in a deteriorated condition and need to be repaired with several potentially needing full replacements. The original manhole and duct system for control cables is in a deteriorated condition and the station has experienced control wire shorts, battery grounds and unwanted circuit opening. The duct bank covers in the yard are bent and rusted and station personnel are hampered to perform repairs by the overall condition of the duct bank. Single control cables cannot be easily removed to replace without adversely affecting adjacent control cables in the same ducts. The 40 year old 115 kV oil filled breakers exhibit minor 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 notably increasing. Each of the oil breakers has aged bushing Potential Devices which have been another source of failure. Some of the 12 kV secondary breakers, are 1950 vintage and have historic mechanism problems. The control room building is in very poor condition needing painting and the flooring repaired. The 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.

- **Lighthouse Hill:** This station 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 the Clay station in Syracuse. In addition, the station provides a direct source of off-site power and black start capability to the Fitzpatrick Nuclear Station. The disconnect switches are in a very poor and hazardous condition, with insulators failing frequently. Most of the oil circuit breakers ("OCBs") are in fair condition, but several are obsolete and would pose a challenge to repair. Seven OCBs are located 200 feet from the Salmon River, which is located below the yard elevation. The station is located approximately one 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.

- **Rotterdam:** This 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 supply for Schenectady. Rotterdam is supplied from the Porter Lines #30 and #31 and from Bear Swamp on the E205 line to Massachusetts. There have been three (R23, R24 and R84) catastrophic failures of Federal Pacific Electric RHE breakers at Rotterdam. In addition, two of the three 230kV auto transformers are candidates for replacement (#7 and #8 transformers).

Aggregate funding for these six substation projects will be $2.8 million in FY11, $8.9 million in FY12, $58.9 million in FY13, and $68.7 million in FY14, for a total of $139.3 million for the rate period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. These funding levels are based on conceptual engineering costs for the work at Gardenville and Rome stations and pre-conceptual cost estimates for the remaining stations.

Transformer Replacement Strategy and Program. The unplanned 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. In addition, lead times to replace most power transformers are in the 18 to 24 month range. The scope of this major program includes the replacement of the 39 highest priority transformers based on their condition. Dissolved Gas Analysis ("DGA"), which is a standard and cost-effective condition assessment test, is used to detect anomalous behaviors within transformers which may indicate a developing fault. Transmission transformers are sampled at least annually, with suspected defective units on enhanced sample intervals. Power factor testing of the transformer and their associated bushings and an assessment of the line-tap-changer is performed during routine maintenance. Additional testing such as swept frequency response analysis (SFRA) and winding impedance tests may be recommended if a review of DGA results indicate further analysis is required. Based on the results of these tests a transformer condition score (1 to 4) is produced.

- Code 4 – under active review to identify the transformer has an internal problem or whether there is a benign reason for the behavior. Code 4 transformers are recommended for replacement within 5 years.
- Code 3 – units are suspected of having developing internal faults.
- Code 2 – indicates a transformer belongs to a suspected design group, however, there are no known issues.
- Code 1 – indicates a normal transformer with no known issues.

The condition codes define the requirement to replace or refurbish based solely on the condition of the asset while the replacement priority also includes criticality in terms of safety, environmental or reliability consequences of failure. This distinction recognizes that two assets, both with the same condition code can have different replacement codes because of the consequences of failure.

The scope includes the transformers (including radiators, fans and pumps), associated civil works, surge arresters and bus connections. 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. Examples of transformers to be replaced under this project include those at Altamont, Harper, Solvay, Teal and Swan Road. The program will be funded for $4 million in FY11, and $7 million each of FY12, FY13 and FY14, for a total of $25 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. The estimated in-service date for this project is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, line 5.

U Series Relay Strategy and Program. 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 are installed on a number of important 345kV lines. Replacement parts and support for the Westinghouse U Series relays are no longer available, making continued maintenance of these devices very difficult. 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 program will improve the overall dependability of the protection system. The more modern replacement relays will have the capability of providing fault and operational data which is currently not available. There are four different projects within this program. The work is necessary to avoid a negative effect on protection schemes, resulting in increased reliability risks to the Bulk Power System. This program will be funded for $2.3 million in FY11 and $0.7 million in FY12, for a total of $3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheets 24-25.

Steel Tower Strategy. Only one project remains in the steel tower strategy: South Oswego-Lighthouse Hill. Beyond this the overhead line refurbishment program will address longer-term steel tower replacement projects that were previously planned under the steel tower strategy. The remaining project will be funded for $4.5 million in FY11 and $0.4 million in FY12, for a total of $4.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24.

<u>Other Asset Condition</u>

Leeds Static VAR Compensator (SVC). This project is required to address the decreasing reliability of the SVC and obsolescence issues. Leeds SVC, installed in 1987, has shown declining reliability in the last six years. In February 2003, ABB, the manufacturer of the SVC notified the Company that technical support would be discontinued. 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. 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 service territory, and other electric customers located east of the NYCE boundary. 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. Many of these incidents have resulted in unplanned 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. Doing this project will reduce the likelihood that the Central-East interface will be de-rated by

100MW. This program will be funded for $5.9 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 22.

PIW Prospective Projects. In 2009/10 a budgetary reserve item for Problem Identification Worksheets ("PIWs") was introduced into the capital investment plan to recognize that a number of high priority, low cost, capital projects will inevitably arise during the year and that should be undertaken. PIWs are prioritized and engineering solutions for the highest priority are developed within year. Examples include the replacement at Geres Lock of fourteen 115kV manual disconnect switches and the replacement at Harper station of circuit switchers 2023 and 2024. This prospective program is based on historical levels of PIW activity and will be funded for $1.0 million in FY11, $1.5 million in both FY12 and FY13, and $3 million in FY14,, for a total of $7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23.

Transformer Replacement – Packard & Gardenville. In addition to the proposed transformer replacement strategy (discussed previously in the testimony), there are a number of General Electric 230/115kV transformers fitted with LR9 load tap-changers that are known to be in poor condition. Dunkirk transformer bank (TB) 31 failed in October 2007 and was replaced. Four similar transformers manufactured between 1957 and 1958 remain in-service at New Gardenville and Packard substations. The DGOA analysis on the Packard TB3 indicates an upward trend in combustible gases and the replacement of all four of these transformers is needed.

All four transformers have known condition issues, are categorized as condition 4, and are expected to fail within the next 5 years if stressed. If any one of these transformers failed, securing the Buffalo area network against the loss of a second transformer would require the Company to dispatch local generation. This program will be funded for $10.15 million in FY11, and $2.8 million in both FY13 and FY14, for a total of $15.75 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23. The estimated in-service date for the New Gardenville TB3 and TB4 under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 15.

Surge Arresters. This program is driven by reliability, safety 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 be replaced due to moisture ingress (degradation was evident in 75% of arresters tested). There are approximately 700 surge arresters at 115kV and above installed on the Company's system. Information suggests that up to 79 percent of all surge arresters are the silicon carbide type, with a large volume estimated to be in a state requiring replacement. 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. As the arresters are predominately installed on transformers, outage availability will limit this program and therefore replacement will be undertaken during 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 program will be funded for $0.25 million in FY12, $2.7 million in FY13, and $2.6 million in FY14, for a total of $5.56 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23. Different project stages will close throughout the program life, with closing occurring 12 months following expenditure of the funds.

<u>Sub-Transmission and Distribution</u>

Sub-Transmission Steel Tower Replacement Strategy and Program. This strategy and program provides an approach to managing more than 3750 of the Company's sub-transmission and distribution steel towers. (Wood poles are addressed in the Inspection and Maintenance strategy.) This strategy is focused on system sustainability, and is designed to prevent steel members from deteriorating to the point of structural failure under expected mechanical loading or becoming weak to the point of compromised safety. Several towers have been identified for replacement with additional locations expected. The Sub-Transmission Tower Replacement Strategy is funded at $0.75 million in FY11, $2.25 million in FY12, $3.75 million in FY13, and $5.25 million in FY14, for a total of $12 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 20. Different project stages will close throughout the program life, with closing occurring 6 months following expenditure of the funds.

Sub-Transmission System Strategy. This strategy proactively manages planned refurbishment and or replacement of sub-transmission overhead lines and their associated assets to ensure the sub-transmission system continues to deliver in a safe and reliable manner for the foreseeable future. This strategy is condition based and incorporates information gathered by field inspections, the aerial helicopter patrol performed in 2008 and reliability performance, and is aimed at maintaining the reliability of the sub-transmission system, which provides supply to the majority of the Company's 4.16kV and 4.8kV substations, as well as some 13.8kV substations. The Sub-Transmission System Strategy is funded at $16 million in FY11, $18 million in FY12, and $9.7 million in FY13, for a total of $43.7 million for the period. Details for these projects are included in Exhibit __ (IOP-1), Schedule 8, Sheets 20-21. Examples of major projects that are components of the Sub-Transmission System Strategy include:

- **Lake Clear – Tupper Lake #38 Line Rebuild.** The Lake Clear – Tupper Lake #38 Line is a 46kV Line 20.3 miles long that feeds 693 customers and also the Gilpen Bay Substation. Rebuild of the line is required to replace deteriorated poles, conductors and insulators identified through inspections. Approximately 7.1 miles of 1/0 Cu will require re-conductoring. Replacement of deteriorated conductor and poles will reduce the risk of customer interruptions in the northern Adirondack area. The project is funded at $1 million in FY11, $2 million in FY12, and $1 million in FY13.
- **Batavia - Attica #206 Line Rebuild.** The Batavia – Attica #206 line is a 34.5kV line. This project will replace 97 deteriorated structures that require replacement based on inspection results. An additional 38 poles will be relocated due to severe wetland conditions to an adjacent railroad right of way. The project is funded at $2.5 million in FY11, and $0.5 million in FY12.
- **N. Leroy – Attica #208 34.5kV Line Refurbishment.** N. Leroy – Attica Line #208 is a 34.5kV 21.9 mile long line. The #208 line serves three distribution stations in Genesee County: Attica, Linden and

Sheppard. Confirmed by a field survey, the Attica - N. Leroy #208 line is in need of significant refurbishment. Numerous poles date back to 1940 and many of the structures are severely decayed. Reliability and safety are the prime drivers for this project. There are 235 of the 526 existing structures in deteriorated condition and need replacement. A small section of the line will be relocated from wetlands. A line inspection report was completed by engineering contractor, TRC. All poles to be replaced were rated 4 out of 5, on the Company's rating scale for wooden transmission poles, with 5 being the worst. The project is funded at $1.1 million in FY11, and $1 million in FY12.

- **Battenkill-Cement Mountain-Cambridge #2 Line and #5 Line.** This project will refurbish and replace poles on both these 34.5 kV lines and address safety and reliability concerns. The lines are part of a 34.5kV network and supply three hydro generators and five industrial customers. The peak loading on the #2 line is approximately 4.5MWs and the peak loading on the #5 line is approximately 7.3MWs. The poor condition of the pole plant could result in a pole failure that would create a hazard and result in customer outages. This project is funded at $1.1 million in FY11, and $1 million in FY12.
- **Rathbun – Labrador #39 34.5kV Line Rebuild.** This project will replace 193 deteriorated single wood pole structures on the Rathbun –

Labrador #39 34.5kV Line. The line is 27 miles long and serves five (5) rural substations south of Syracuse and one radial customer. The primary drivers for this project are safety and reliability: Replacement of these assets will reduce the risk of customer interruptions related to deteriorated equipment; and address the condition of the existing pole plant, much of which is leaning and in a deteriorated state with woodpecker/insect damage, split pole tops, and shell rot. The project is funded at $1 million in FY11, and $1 million in FY12.

- **Gloversville – Canojaharie #6 69kV Refurbishment.** Out of 212 structures on this line, 112 will be replaced due to structural inadequacy. Special structure framing specifically designed for this 69kV line will be used, as will an overhead ground wire for all new poles to ensure proper phase spacing, mid-span clearance to ground, and protection over all three phases with a shield wire. Replacing these structures will improve reliability to customers. The project is funded at $1 million in FY12, and $1 million in FY13.

Distribution Substation Transformer Replacement Strategy and Program. This strategy addresses a population of 807 Distribution Power Transformers (primary voltage 69kV and below), and provides both proactive asset replacement of individual units identified by condition and risk, in conjunction with capacity planning requirements, and reactive replacement of transformers which have failed in service. This is performed through:

- Ranking substation transformers in terms of asset condition, failure impact and risk,
- Identifying the nominal replacement volume of substation power transformers based on installed MVA and best analytical estimates of transformer life expectancy (currently 65 years).

The risk/adverse impact of delaying this program includes:

- Catastrophic transformer failure resulting in widespread dissemination of oil, possibly burning, and related collateral damage to the station infrastructure and environment,
- Unplanned replacement of a failed unit may take several days as opposed hours for a planned replacement,
- Contingent failures may cause significant widespread interruptions (sub-transmission and heavily loaded distribution units have high contingent impacts, compared to transmission units).

The main driver for this program is the need to address poor condition units. An individual unit that fails may have a significant impact on reliability (up to 355,000 CMI per event) with a SAIDI contribution of up to 0.3 minutes, on average. In addition, lead times for replacement units may be 6 months to 2 years (current lead time for a 5 MVA transformer is 6 months).

Examples of Distribution Substation Power Transformers being reviewed for replacement and/or re-configuration include: Fisher Avenue Station 27, 34.5-13.8kV, 6.25MVA; Fayetteville, 34.kV-2.4kV, 6.25MVA; French Creek Station, 34.5kV-13.8kV, 3.75MVA; and Chrisler Ave, 34.5kV-4.16k, 3.65MVA. The Distribution Substation Transformer Replacement strategy is funded at $1.5 million in FY11, $1.5 million in FY12, $1.5 million in FY13, and $2 million in FY14, for a total of $6.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 19. .

Substation Circuit Breaker Strategy and Program. This strategy and replacement program targets obsolete and unreliable breaker families. The strategy defines unit condition and a formal spares policy to manage this large asset class. There are approximately 4,100 distribution and sub-transmission substation circuit breakers in this population. The method for managing substation breakers and reclosers consists of periodic maintenance, refurbishment and replacement on condition. Units with obsolete technology, such as air magnetic interruption, have been specifically identified for replacement. Additionally, where cost effective and where their conditions warrant, the opportunity will be taken to bundle work and replace disconnects, control cable and other equipment associated with these circuit breakers. The distribution strategy is funded at $3.5 million in FY11, $1.7 million in FY12, $3.5 million in FY13, and $7 million in FY14, for a total of $15.7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 17. The sub-transmission strategy is funded $0.3 million in FY12, $2.6 million in FY13, and $2.8 million in FY14, for a total of $5.7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 19. Different project stages will close throughout the program life, with closing occurring 9 months following expenditure of the funds.

Substation Metalclad Switchgear Replacement Strategy and Program. This strategy replaces switchgear installed prior to 1970 beginning with those metalclad switchgear that have sustained a failure or are of a manufacturer type where a failure has occurred. There are approximately 220 metalclads in service operating at 13.2kV, 4.16kV and 4.8kV. Of these, approximately 70 were installed in the 1960s and 1970s. 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 metalclad switchgear, 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 Substation Metalclad Replacement Strategy and Program would replace two metalclad substations per year using assessments based on age, manufacturer and conditions as determined by visual and electro-acoustic test results. The Altamont and the Market Hill Substations are two distribution locations that have been identified for replacement in FY11. The North Troy Substation and Oneida Substation are two sub-transmission locations that have been identified for FY11. The distribution strategy is funded at $1.2 million in FY11, $4.8 million in FY12, $5.0 million in FY13, and $3 million in FY14, for a total of $14 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 18. The sub–transmission strategy is funded at $1.25 million in FY11, and $1.9 million in FY12, for a total of $3.19 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 20. Different project stages will close throughout the program life, with closing occurring 9 months following expenditure of the funds.

Indoor Substation Strategy and Program. The purpose of this strategy and program is to review of site locations, determine rebuild options, and rebuild 22 indoor substations located in Buffalo and 6 indoor substations located in Niagara Falls. This refurbishment plan is required to remove safety and equipment failure risks based on asset conditions. These indoor substations were built in the early 1930s and are over 70 years old. These stations are 23kV-4.16kV. Key drivers for replacement include:

- Safety - The stations have inherent hazards/safety risks due to design and equipment condition and have been the subject of ongoing meetings with represented employees.
- Capacity and Loading - 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 at locations already rebuilt.
- Asset Condition - The bay 1-3 sections of the Buffalo stations date from 1929 to 1931. Some stations have a 4th bay that was

> added in the 1940s and 50s. This places equipment ages from 50 to 75 years, which is beyond their designed service life, significantly increasing the probability of failure. In addition, obsolete equipment often does not meet current requirements for fault interrupting capability, operating interfaces, and personnel safety.

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. The substation and distribution line strategy is funded at $8.6 million in FY11, $13.9 million in FY12, $17.7 million in FY13, and $17.7 million in FY14, for a total of $57.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 18. The 23kV sub-transmission line portion of the strategy is funded at $0.66 million in FY11, $1.9 million in FY12, $1.8 million in FY13, and $1.8 million in FY14, for a total of $6.16 million for the period as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 20.

Distribution Substation Battery Strategy and Program. The intent of this strategy is to replace batteries beyond 20 years old. There are slightly more than 200 distribution batteries systems in Niagara Mohawk distribution substations. The 20 year limit is based on industry best practice in managing battery systems. 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. This strategy will assist in ensuring battery systems meet current operating requirements and will perform their designed function. Delaying this replacement strategy will lead to control problems in substation operations. The strategy is funded at $470,000 in FY11, $160,000 in FY12, $405,000 in FY13, and $825,000 in FY14, for a total of $1.86 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 17.

Primary Underground Cable - Distribution and Sub-transmission. The distribution and sub-transmission underground cable asset replacement strategy replaces cables that are in poor condition and those identified 60 years or older with known condition issues. Replacing these cables on a planned basis is highly desirable since the work involved often includes civil work. Customers are directly affected by these extended repairs where alternate feeds are not possible or available. Sub-transmission primary cables also provide supply to the many of the 4.16kV and 4.8kV substations and some 13.8kV substations in densely populated areas such as Syracuse, Buffalo, Utica, Albany, and

Schenectady. Examples of distribution cables currently being reviewed include: Mill St Network Cables in the Central Division; Corliss Park 4kV Cables in the Eastern Division; and Buffalo Station 27 4kV cables in the Western Division. Examples of sub-transmission cables currently being reviewed include: 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. The Distribution strategy is funded at $3.4 million in FY11, $4.5 million in FY12, $3.0 million in FY13, and $4.5 million in FY14, for a total of $15.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 17. The sub-transmission strategy is funded at $3.5 million in FY11, $6.6 million in FY12, $7.8 million in FY13, and $11.6 million in FY14, for a total of $28.7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheets 19 and 21.

Underground Network Asset Replacement Strategy. The underground network asset replacement strategy and program targets the maintenance, monitoring and installation/replacement of: limiters, transformers, protectors, secondary cables and miscellaneous network assets. Network systems include aged assets installed in harsh environments such as manholes and vaults, and require monitoring, maintenance and replacement to maintain the reliability and physical integrity of the equipment. Though networks generally provide reliable service, when incidents do occur, restoration can end up being very lengthy and costly, with potential to interrupt large numbers if customers due to the high density areas the networks serve. Niagara Mohawk has underground network systems located in Albany, Syracuse, Buffalo, Watertown, Troy, and Utica.

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 incidents. Load flow studies have also been completed on the Buffalo, Syracuse Ash Street, Syracuse Temple Street, Watertown and Troy networks. All networks will have a load flow study performed. The strategy is funded at $2.1 million in FY11, $2.1 million in FY12, $2.0 million in FY13 and $2.25 million in FY14, for a total of $8.45 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 16.

E. <u>Non-Infrastructure</u>

Q. Please discuss the investments the Company plans to undertake in the Non-infrastructure category during the period covered by this rate case.

A. In addition to spending on its electric network, the Company also invests a small portion of its investment budget (<1%) in systems and tools that are not specific to the operation of a particular element of the electric system. Examples include security systems, radio systems, test equipment flood protection and substation building repairs that that are required to support the safe and reliable operation of the network. Exhibit __ (IOP-1), Schedule 7, illustrates the amount the Company plans to spend in the Non-infrastructure category in FY11-FY14.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the Non-infrastructure category.

A. Below we provide a description of major projects and programs in this category, segregated by portion of the electric system they address. Additional information on these programs is included in Exhibit __ (IOP-1), Schedule 8, Sheet 26.

<u>**Transmission**</u>

Physical Security NY Bulk Power System Substations. This strategy is driven by the NY DPS recommendation to install additional physical security measures at our BPS substations. The benefits from this

BPS security strategy arise from deterring and detecting unauthorized access to BPS substations. This program will be funded for $100,000 in FY11, $6 million in FY12 and $3 million in FY13, for a total of $9.1 million for the period.

Flood Mitigation. Overall the predicted weather changes indicate that the types of heavy rainfall events that have occurred in the Northeast in recent years will become increasingly common, raising the risk of floods and flash floods. Flooding at sites such as Gardenville and Oswego have already occurred as well as sites along the Mohawk River valley (June 2006, St. Johnsville and Inghams). A study of the flooding risk concluded that flooding events were likely to increase. Sites that were classed high risk (or sites where no FEMA Insurance Rate Map existed) were then subject to a more detailed assessment in which the following factors were ascertained i) proximity of the site to water features such as streams, lakes and oceans, ii) proximity to designated FEMA flood zone, iii) elevation of the site above nearby water surface elevation and iv) the reliability of FEMA information e.g. date of maps. From this more comprehensive survey and site visits a small number of sites were identified that had an elevated risk and that measures may be required to reduce the likelihood of flooding. These sites are Adams, where the control room is located 2’ below ground level, Amsterdam which has low lying control panels, Ingahms, Lighthouse Hill which is located in the lee of a dam wall and St. Johnsville which is located next to the Mohawk River. Preventing flooding will result in enormous saving associated with equipment that could otherwise be damaged or destroyed. This project is categorized within the "Other" program and is budgeted at $3 million; however, the scope and timing of work has not been finalized. This program is currently funded at $2 million in FY13 and $1 million in FY14, for a total of $3 million for the period. These amounts are pre-conceptual level estimates and likely to change during detailed engineering.

Sub-Transmission / Distribution

General Equipment – These blanket programs are for field equipment, tools or specific equipment requirements which have costs are greater than $200/per unit and are not included in other capital projects. A reserve is also set up to budget for purchases of equipment known to cost more than $100,000. These reserves are based on historical calculations for specific projects within the category. The driver for this blanket is to enable the purchase of necessary non-infrastructure equipment involved in support of operations. This blanket is funded at $2.2 million in FY11, $4.3 million in FY12, in $4.5 million in FY13, and $4.6 million in FY14, for a total of $15.6 million for the period.

Distribution – Telecommunications. The driver is to allow for the purchase of non-infrastructure telecommunications related equipment involved in support of operations. This blanket is funded at $1.0 million in FY11, $1.1 million in FY12, $1.1 million in FY13, and $1.1 million in FY14, for a total of $4.3 million for the period.

Q. Does the Company's revenue requirement in this case include cost of removal ("COR") associated with the capital investment plan?

A. Yes. In addition to the capital costs discussed above, there is a level of COR required to implement the Company's infrastructure investment plan presented in this case. As reflected in Exhibit (RRP-6), Schedule 1, Sheet 5 of the Revenue Requirements Panel, the Company anticipates projected Cost of Removal (COR) of approximately $18.7 million for the last six months of FY10, $38.3 million in FY11, $46.6 million in FY12, $51.9 million in FY13 and $54.9 million in FY14.

Q. What type of activities does the Company associate with 'Cost of Removal'?

A. The Company defines removal as any work on existing assets that results in said asset being removed from the asset inventory, whether or not a different asset is subsequently added in its place. This type of work would include, but is not limited to, all the activities associated with the disconnection, removal and disposal of high voltage items of equipment such as circuit breakers and transformers; disconnection, removal and disposal of secondary items of equipment such as relays and control equipment; removal and/or demolition of foundations; disconnection, removal and disposal of insulator strings; removal of wood poles or steel structures; and disconnection and removal of shield wire.

Q. Please explain the basis for the projected COR increases for the rate years?

A. COR is estimated using recent historical experience as an indicator of the likely level of future expenditure. A ratio of actual COR to infrastructure investment for distribution, transmission and sub-transmission, typically over a period of the last three years, is calculated. The resulting percentages are applied to the amount of infrastructure investment that is projected to be spent in each category and this derives the COR amount over the planning horizon.

F. Annual Budget Process

Q. Please provide a brief summary of how the Company developed its budget for the infrastructure plan?

A. We provide a brief description of the Company's budgeting process here. However, as discussed previously, the Company also addresses the management audit report recommendations, including those related to the budget process, in the implementation plan included with Mr. Zschokke's testimony in this case.

Each year, the Company develops an Annual Work Plan designed to achieve the overriding performance objectives of the business unit (safety, reliability, efficiency, and environmental performance). At the outset, the Annual Work Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by spending category: i.e., Statutory/Regulatory, Damage/Failure, System Capacity and Performance and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects.

In order to optimize the plan budget and resources, a risk score is assigned to each project. The project risk score is generated by a project decision support matrix that assigns a project risk score based upon the estimated probability and consequence of a particular system event occurring. The project risk score takes into account key performance areas such as safety, reliability and environmental, while also accounting for criticality. Historical and forward looking checks are made by spending rationale to identify any deviations from expected or historical trends.

All mandatory programs and projects known at this time are included in the plan. Mandatory programs and projects (i.e., Statutory/Regulatory and Damage/Failure spending rationales) include FERC bulk power system requirements, new customer and generator connections, regulatory commitments, public requirements that necessitate the relocation or removal of our facilities, safety and environmental compliance, and system integrity projects such as response to damage/failure and storms.

Once the mandatory budget level has been established, programs and projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) are reviewed for inclusion into the plan. Plan inclusion/exclusion for any give project is based on several different factors including, but not limited to: project new or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the total cost and outage planning. The objective is to establish an optimized capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project.

The portfolio, along with supporting risk analyses, is presented to the Company's senior executives and ultimately the Board for review and approval. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible to manage to the approved budget.

Q. Why does the Company modify or adjust its budgets?

A. From an overall perspective, the Company's objective is to arrive at a capital budget that is the optimal balance in terms of making the investments necessary to maintain and improve the performance of the system for customers, while also ensuring a cost-effective use of the Company's available resources. Because of the time horizon over which the Company must budget its infrastructure investments, there are inevitable changes in budgets and project estimates over time. Such changes may be due to changes in project scope, changing material or resource costs, or changing customer needs, or a more refined estimate based on where the project is in its development.

Q. At what stage in the project evolution process are the projects that are included in the Company's infrastructure investment plan presented in this case?

A. The plan presented in this case represents the Company's best information on the investments it will need to make in order to sustain the safe, reliable operation of the electric system. As described above, many of the projects are already in-process or soon to be in process. Estimates for those projects are quite refined. Other projects are at earlier stages in the project evolution process. The budgets for those projects are accordingly less refined, and are more susceptible to changes in scope and budget.

Typically, projects to be delivered in the near term are more firm in their cost estimates than out-year projects. In addition, project estimates may vary based on where they are in the project evolution stage. That is, project estimates that go into developing the Company's infrastructure investment budget become more refined as they progress from the initiation stage to the delivery stage. The plan is continuously reviewed, following approval and during the current year, for changes in assumptions, constraints, as well as project delays, accelerations, outage coordination, permitting/licensing/agency approvals, and system operations, performance, safety, and customer driven needs that arise. The plan is updated accordingly throughout the current year. A graphical depiction of this "project evolution" process is included in Exhibit __ (IOP-4).

Initial estimates, prepared during project development, have a margin of error of plus or minus fifty percent. This is the wide end of the funnel. The margin of error grows progressively smaller as project development proceeds and the engineering scope and cost estimates are refined and subsequently finalized at Project Sanction. This is the narrow end of the funnel. Thus, by process, estimates made at the early stage of a project have no bearing on the efficient delivery of a project post project sanctioning

Project risks are now identified and managed earlier in the process and these project risks include variation in permitting times, field conditions that are different from what initial field reviews highlighted (particularly with respect to underground/civil work), and the availability of outages from NYISO.

Q. Are there other approval processes that are conducted in relation to the annual budget?

A. Yes. As stated above, the result of the budgeting process is the approval of a total dollar amount for capital spending in the budget year. In addition to this planning and budgeting process, specific approval must be obtained for any Strategy, program or project within the Annual Work Plan. Approval is obtained through a "delegation of authority," or "DOA," requirement prior to proceeding with project work including engineering and construction. Each project must receive the appropriate level of management authorization via a Project Sanction Paper prior to start of any work. Approval authority is administered in accordance with the Company's DOA governance.

Q. What is included in Project Sanction Papers you mentioned above.

A. Projects with projected scope and costs above established thresholds must be presented as appropriate to management. Projects presented must be accompanied by a detailed Project Sanction Paper ("PSP") for approval. The PSP must include a written summary of various major factors that are considered in any decision to allow the project, including:

- <u>Project Background, Description and Drivers</u>: These sections provide a high-level overview of the project and the factors driving the need for its completion.

- Business Issues, Options Analysis: This section provides a summary of the business issues involved in the project. The options analysis discusses other potential courses of action including the impacts of a "do nothing" strategy.
- Financial Impact and Cost Summary: This section provides an economic analysis of the proposed project. The nature of the economic analysis differs depending on the nature of the project.
- Investment Recovery: This section evaluates any factors relating to the recovery of the investment.
- Project Schedule, Milestones and Implementation Plan: This section describes any timing implications and start-up schedules.

Once an approved project is completed, the project sponsor is responsible for preparing closure papers, which present information on a number of factors including a discussion of whether and to what extent project deliverables were achieved and lessons learned as a result of project implementation.

Q. What is the process for re-sanctioning capital projects?

A. Capital projects are authorized with either a conceptual or project-grade estimate following preliminary engineering. Reauthorization is required if the project cost is expected to exceed the estimate plus the variance range identified in the PSP. The reauthorization request must include presentation of the original authorization, the variance amount, the reasons for the variance and the details and costs of the variance drivers, as well as the estimated impact on the current year's spending. Project reauthorizations above established thresholds require re-approval. Project spending is monitored monthly against authorized levels by the project management and program management groups. Exception reports covering actual or forecasted project spending greater than authorized amounts are presented and reviewed monthly. Significant projects also require re-sanctioning if the project completion date is delayed more than three months beyond the approved date.

Q. How does the Company's plan provide for unbudgeted, or "walk-in," projects?

A. The Company includes certain Reserve line items in its Spending Plan, by budget category, to allocate funds for projects whose scope and timing have not yet been determined. In such cases, historical trends are used to develop the appropriate reserve levels. As the specific project details become available, "walk-in" projects are added to the plan with funding drawn from the reserve funds. The majority of projects that are "walked–

in," are the result of in-year occurrences in mandatory project categories such as damaged or failed equipment, customer or generator requirements or regulatory mandates. Reserve funds are also established for high priority risk score projects that are may arise during the current year in response to unforeseen system reliability or loading concerns. The Company tracks and manages budgetary reserves and walk-ins as part of its investment planning and current-year spending management processes.

Q. The recent Management Audit report released on Niagara Mohawk criticized the Company's cost estimation performance. How can the Company be confident that its capital portfolio reflects projects delivered in a quality manner given the Management Audit findings?

A. As indicated in its response to the management audit report, the Company found the management audit process to be helpful in identifying areas for potential improvement of its systems and processes in order to perform more efficiently and effectively going forward. Steps the Company is taking to address the final recommendations are described in the implementation plan that is included with Mr. Zschokke's testimony, including measures to improve project estimating performance.

Notwithstanding the importance of sound estimating, the Company does not believe that inaccurate project cost estimates would, by themselves, affect the Company's delivery of projects in a high quality manner. First, projects are identified using a risk-based approach (as described previously), which is independent of estimating accuracy. As projects progress, and additional scope, resources, duration, and scheduling information becomes available, the project estimate is refined.

Q. What steps is the Company taking to address the Management Audit recommendations regarding estimation?

A. One of the Company's major initiatives in this area is the creation of the Estimating Center of Excellence (ECoE). The ECoE was established to enable the groups and individuals responsible for project estimates to perform this task with greater consistency and accuracy. The ECoE is charged with identifying and implementing the process improvement that will overcome deficiencies in project cost estimating. The ECoE will establish and maintain the Company's actual cost data base and estimating proficiency through the use of appropriate estimating software, user training, process documentation, and continuous performance monitoring. The successful results of these efforts will provide the infrastructure investment plan with high quality, accurate cost estimates.

The ECoE has defined the process by which project estimates mature as the need date for the defined work advances. Estimates will progress through a series of accuracy grades over the project's development timeline. The estimating software chosen for use by the ECoE, has the flexibility to modify the assumed values and estimating units as the project scope is progressively defined. This enables the estimator to effectively use the tool to furnish the investment plan with increasingly accurate cost estimates.

The software tool was configured and uploaded with Distribution and Transmission line and substation estimating units, based upon the knowledge of experienced designers and project managers. As part of its charter of responsibilities the ECoE will provide routine updates to the estimating units and underlying assumptions. Some of these revisions will result from the continuous monitoring of the actual tolerance achieved by the different grades of estimates. The ECoE will act to identify causes for those variances that have been detected and initiate the corrections to estimating units/processes/etc. as required.

G. Delivering the Investment Plan

Q. Please describe how the Company will deliver the proposed infrastructure investment plan over the course of the rate plan.

A. Historically, the Company has delivered its construction plan through a variety of arrangements. However, the business environment in which the Company delivers its capital program is changing. Through optimization of its internal workforce and contracting arrangements, the Company can realize sustainable value for customers through cost-effective, reliable, and improved capital plan delivery.

The Company's portfolio of construction delivery resources include:

- Distribution Alliance Contracts;
- Transmission Regional Delivery Ventures (RDVs);
- Enhanced Internal Construction Capabilities;
- Traditional "project-by-project" competitive bidding; and
- "Turn-Key" Engineer, Procure, and Construct (EPC) events for specialized installations.

Q. Could you describe the mix of construction resources you refer to?

A. *Distribution Alliance Contracts*

Following a year-long competitive procurement event, Harlan (a subsidiary of Myr Group) was selected to deliver Niagara Mohawk's distribution line construction program under a fixed-price unit rate agreement over a three-year contract period (with an option to extend 2 years). The reduced unit and tendering costs resulting from the aggregated bid process are already factored into the Company's investment plan amounts for the rate plan period. In addition to these competitively bid units, the Company anticipates additional benefits related to reduced tendering timeframe, improved scheduling, and a stable workforce with increased safety, customer, and standards training.

Harlan's performance will be evaluated against its unit costs, workload delivery, and agreed Key Performance Indicators (KPIs). For each project, Harlan and Niagara Mohawk jointly complete a constructability review to agree to project scope, units, and schedule. A Work Request will be executed to document these delivery criteria and the workplan agreed to efficiently deliver the work. To further incentivize performance and improved customer value, Harlan is subject to a KPI scorecard focused on Safety and Environment, Quality, Delivery, and People performance measures. The release of work in subsequent years is dependent on satisfactory performance against these criteria to ensure acceptable costs and workload delivery performance. The Alliance contracts do not guarantee a minimum volume of work, nor are they exclusive arrangements.

Transmission Regional Delivery Ventures (RDVs)

The Company is improving its delivery of the infrastructure investment plan via the introduction of the Transmission Regional Delivery Venture (RDV). This RDV will operate under a long-term contract arrangement (i.e., 5-year, with an option for 3 more years) that includes the integrated provision of detailed design, project management and construction services to deliver an assigned portion of the Company's capital investment program. The RDV contract includes comprehensive "full open book" audit rights. The contract does not guarantee a minimum volume of work or exclusivity.

The selected RDV, entitled Northeast Power Alliance (NEPA), is a joint venture comprised of AMEC, Michels Corp, and Vanderweil Engineers. Assignment of project work to NEPA, has resulted in a baseline savings of $60 million for Niagara Mohawk and this has already been removed from the 5-year capital plan. These savings include a combination of the reduced unit costs and fees resulting from the competitive RDV procurement event plus reduced tendering costs and improved scheduling. Another included benefit is an insurance premium savings by direct sourcing the Transmission portfolio to the insurance market for OCIP (Owner Coordinated Insurance Program) versus traditional insurance coverage. To leverage its buying power, the Company supplies all plant materials to the RDV except for consumable items.

To further incentivize performance and improved customer value, the RDVs are also subject to a KPI scorecard focused on Safety and Environment, Quality, Delivery, and People performance measures. The KPIs ensure efficiency is not at the expense of performance by putting the RDVs' share of any efficiency "gain" at risk, subject to meeting certain KPI performance.

Enhanced Internal Construction Capabilities

The Company continues to enhance its own internal transmission and distribution construction capabilities in order to perform a 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 56 line workers to perform distribution construction line work typically performed by contractors in the past. Pilot development began in October 2009, with pilot implementation targeted for April 1, 2010 through April 1, 2011. These new construction capabilities enable an internal workforce, dedicated to capital construction, to perform a larger portion of the 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 "project-by-project" competitive bidding

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 deliver niche services or competitively-priced projects based on specific 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.

Q. Why has the Company chosen to perform a portion of the infrastructure investment work presented in this rate case using the RDV mechanism rather than the traditional process of selecting contractors for projects on the basis of competitive bids?

A. One of the primary value drivers of the Company's RDV model is the development of long-term, integrated supplier relationships aimed at capturing the value of negotiating a large portfolio of work. Aggregation of the volume of work through a single Procurement Event with multiple bidding entities allows for increased competitive prices and schedule improvements through reduced procurement time and program/resource optimization. The integrated RDV model, which includes detailed design, project management and construction services, optimizes design efficiencies and construction delivery through end-to-end accountability and constructability focus. In addition, the Company, like other utilities across the country, is faced with substantially increasing capital investment requirements. These requirements cannot be effectively met by increases in internal staffing or use of traditional contracting resources alone. Further, given the anticipated increase in infrastructure spending throughout the country, it is reasonable to expect that skilled engineers, designers and craft workers could be in short supply during the plan period. By entering into long-term arrangements with qualified partners, the Company is able to secure and retain highly skilled personnel and construction equipment needed to deliver on the investment plan. The contracted entities are familiar with the region and are capable of working in accordance with company standards, and have the capacity to work on multiple related or similar projects.

Q. How will the RDV target costing process generate value for customers?

A. The target cost incentive mechanism encourages the Company and the RDV to generate efficiencies through improved risk management and by equally sharing the difference between the project target cost and the actual costs at project completion. Thus, if actual project costs are below the target costs, the RDV has an opportunity to receive up to 50 percent of the difference between the actual and target costs in the form of a gain share. Likewise, if actual costs exceed target costs, the RDV would receive 50 percent of the amount by which the target is exceeded. Future projects benefit fully from the efficiencies as the unit costs are reduced year on year in line with the reductions in actual cost, known as "cost ratcheting".

Q. Could you please describe what "core team costs" are?

A. Yes. Core Team Costs are RDV management and infrastructure costs that are assessed annually pursuant to the RDV contracts. There are two elements to the RDV Core Team Costs: Core Team Project Specific costs (project-specific costs directly charged to specific projects); and Core Team Overhead (non-project specific resources and costs; allocated on the basis of established allocators). Core Team project specific costs cover the RDV's Project Planning and Preliminary Engineering resources that are providing assistance to the Company to develop specific work proposals and target costs. Non-project-specific resources support and manage the RDV work in the project planning and preliminary engineering, final design, project execution and project closeout stages for work being carried out by the RDV in the year. The RDV submits Core Team invoices to the Company every two weeks that cover the RDV's actual costs, applicable fee, and certain tax expense. Following review by the Company, RDV costs are recorded as either O&M charges or capital. Capital costs are allocated to individual projects. A further description of how the costs are reflected in the revenue requirement is set forth in the testimony of the Revenue Requirements Panel.

Q. Is the Panel aware of other instances where the RDV contracting model has been used successfully?

A. Yes. In the United States, the American Transmission Company ("ATC") has successfully used a similar alliance contracting strategy for the past 3 years on its $2.5 billion, 10-year program of work. This alliance contract has recently been competitively renewed with MJ Electric for a further 4 years and a second alliance, replacing the remainder of ATC's project work, has been awarded to Henkels and McCoy. MJ Electric has quoted savings of between 6 and 12 percent each year for work performed in 2007-2009, when compared to other methods of delivering the work.

National Grid has also used the long term collaborative approach successfully in the UK. National Grid's Gas Alliance arrangement in the UK produced an 18 percent reduction in costs over the first three years it was in place when compared to costs under the prior contracting regime. Likewise, National Grid's UK East Overhead Electricity Alliance has experienced cost reductions of 18 percent in 2007/08 and 3.7 percent in 2008/09 on over $150 million of annual spend compared to the previous models employed.

H. <u>In-Service Dates Reflected in Revenue Requirements</u>

Q. What is the effect of the in-service date of a project on the Company's revenue requirements?

A. The Revenue Requirements Panel addresses this issue in greater depth, but in summary, the in-service date of a project determines when a project is reflected in the Company's rate base for purposes of affecting the revenue requirements.

Q. Could you explain how the Company determined the in-service dates you describe above?

A. Yes. First, it is the Company's objective to establish in-service dates that accurately reflect the estimated actual in-service date. The ability to accurately estimate in-service dates for large projects that are already underway and near completion is obviously greater than for projects that have not commenced and are further out in time. Smaller projects are subject to other considerations when estimating in-service dates. In the case of small projects (which may be more prone to schedule shifts for operational efficiency/bundling or other reasons), or programs comprised of recurring projects that are put in-service throughout the year, it is more difficult to predict definitive in-service dates. Therefore, in developing the in-service dates reflected in this case, the Company estimates actual in-service dates for very large projects (i.e., those with estimated costs greater than $15 million). For programs and projects budgeted at less than $15 million, the Company used in-service dates determined pursuant to accounting closing rules applicable to the type of project or program. Thus, amounts for construction work in progress ("CWIP") and capital expenditure cash flows forecasted from CWIP were estimated to go into service in the month following the applicable period under the closing rule. The relevant closing rule periods were determined based on a historical analysis of CWIP and plant closings. Sample closing periods used by the Company include: transmission substations—12-months; distribution substations—9 months; transmission lines—6 months; distribution lines and street lighting—3 months; meters and line transformers—1 month. For example, assuming a projected expenditure of $100,000 in January related to a distribution line capital project, such expenditure would be deemed closed to plant in-service in the month following the closing rule period, or April.

I. <u>Additional Projects</u>

Q. The Company's plan includes recovery of costs associated with projects identified as "Luther Forest," "Tri-Lakes" and "Hydro One." Would you please discuss these projects and how they are reflected in the Company's investment plans?

<u>Luther Forest</u>

A. Luther Forest Technology Campus (LFTC) is a 1350 acre industrial park located in Saratoga County. The LFTC is being built by the Luther Forest Technology Campus Economic Development Corporation (LFTCEDC) to attract computer chip manufacturing facilities. The new LFTC Park will include 115kV transmission capability to serve the computer chip fabrication facilities. LFTCEDC is currently engineering, purchasing material, and constructing the following facilities: (1) four 115kV transmission circuits; (2) a transition station (Stonebreak Road) which would allow two of the four 115kV lines to transition from underground to overhead; and (3) a 115kV "Luther Forest" switching station. The design and facilities being developed by LFTCEDC are intended to provide highly reliable, redundant service to customers with a need for such high reliability. Nanotechnology computer chip manufacturers, because of the processes they use, often require such high reliability service.

Q. What is the Company's interest in the facilities being built by LFTCDC?

A. The facilities being constructed by LFTCEDC would interconnect directly to the Company's existing transmission system. In addition to enabling service to be provided to computer chip manufacturing facilities in the

LFTC, the newly constructed facilities will become part of the integrated network transmission system. Therefore, once the facilities are constructed, it is anticipated that their ownership will be transferred to the Company, and the Company would own, operate and maintain the facilities going forward. During discussions with FERC staff on a related engineering, permitting and construction services agreement, FERC staff suggested that FERC might have jurisdiction over elements of the transfer agreement, which would require FERC review of the transfer agreement.

Q. At what price will the facilities be transferred to the Company?

A. The cost of the transmission facilities being developed by LFTCEDC is estimated to be approximately $57 million, and is being paid primarily through New York State grant funds, and not being paid by the end use customer or customers. The facilities are being constructed to provide extremely reliable, redundant service considered vital to attract nanotechnology computer chip manufacturers to the newly developed LFTC, which contributes significantly to the estimated $57 million cost. It is the intention of LFTCEDC and the Company that once completed; the facilities would be transferred to the Company for $1. The assets would be put on the Company’s books at that amount, and the corresponding effect on the Company’s rate base would be negligible. However, because of the FERC's potential jurisdictional authority, that agency's determination on the transfer is also expected to determine if the cost of the facilities can be directly allocated to a single developer, which in this case is LFTCEDC. Although the Company and LFTCEDC have agreed to the transfer at $1, and the unique circumstances of the situation justify the contemplated $1 transfer price (e.g., facility designs in excess of the Company's standard design in order to satisfy the unique needs of nanotechnology computer chip manufacturers, construction in advance of firm end-use customer commitments, development intended for New York State economic development purposes funded through State grants), there is uncertainty whether FERC will authorize the transfer at $1. Therefore, the Company's rate base forecast in this case reflects the value of the facilities to be received from LFTCEDC at $57 million in the event that the FERC approves the transfer, but directs the cost of the facilities to be funded by all of the Company's customers. The Company believes there is a reasonable basis for FERC authorizing the transfer under the terms agreed to by the Company and LFTCEDC. However, due to the unclear FERC precedent, the Company's rate base forecast reflects the full amount of the estimated market price of the assets ($57 million). Once the final transfer price is established, the Company will notify the PSC and make necessary and appropriate adjustments to its books of account, and will reflect corresponding changes in the revenue requirement. The Electric Delivery Adjustment Mechanism ("EDAM") is the mechanism by which an adjustment would occur. The EDAM is described in the testimony of the Revenue Requirements Panel.

Q. What is the timing of the anticipated transfer of assets?

A. The project schedule is largely in the control of the LFTCEDC and its contractors. We anticipate that the transfer and energizing of the facilities will take place some time before March 2012. For ratemaking purposes, the Company has reflected the $57 million payment in March 2012.

Q, Is the $57 million cost reflected in the Company's infrastructure investment budgets that the Panel described previously?

A. The $57 million payment amount is not reflected in the Company's infrastructure investment plan described previously; however, the payment is reflected in the Company's revenue requirements calculations as described above.

Q. Are there other facilities being developed in the area of the LFTC that relate to that project?

A. Yes. In addition to the specific facilities investments being developed by LFTCEDC, additional investment is needed to upgrade seven substations with new high speed relay and communication equipment required for nanotechnology manufacturing. The addition of two new 115kV breakers at Battenkill substation and the expansion of Malta substation to accommodate a new underground cable are being constructed by LFTCEDC. The upgrades on the Company's existing system are to accommodate the new LFTC interconnection at a cost of approximately $9 million.

Q. Are the costs associated with these connection upgrades reflected in the Company's infrastructure investment forecast?

A. Yes they are. Although the need to upgrade the interconnection facilities results from the need to accommodate the new LFTC facilities, it is appropriate to include these costs in the Company's investment plan and rate base because these facilities are part of the existing interconnected system and they provide benefits to both Niagara Mohawk and its customers. First these upgrades are replacing older electromechanical relays that are obsolete. In addition, the upgrades will include communication equipment that will provide high speed protection allowing the system to remove faults much faster than with current protection schemes. Removing faults from the system faster provides higher power quality in the area by reducing the voltage dips caused by faults. It also can reduce the stress on existing high voltage electrical equipment in the area potentially extending the life of equipment such as transformers and cables that are exposed to the fault currents.

Q. Could you please describe how the Northeast Regional Reinforcement Project ("NRRP"), described earlier in your testimony, relates to the LFTC project?

A. Yes. As mentioned previously, the NRRP was developed based on a comprehensive assessment of the reliability needs of the northeast region of the state. This assessment considered load growth, reliability needs and asset conditions in the region, and the resultant project elements address these factors. The NRRP was developed independent of and without consideration of the LFTC project, and then refined to insure compatibility with the LFTC project. As a result, the NRRP does not include elements intended to specifically interconnect the LFTC project. However, because the anticipated new customer load at the LFTC will increase area demand sooner than anticipated in prior studies, some portions of the NRRP will be accelerated and constructed earlier than initially envisioned. Therefore, while the overall design and level of investment relating to the NRRP is not significantly affected by the LFTC project, the timing of the construction of certain portions of the NRP will be accelerated.

<u>Tri-Lakes</u>

Q. Please describe the "Tri-Lakes" project.

A. Niagara Mohawk provides electric transmission service to several communities within the Adirondack Park. Rapidly increasing load growth in the Villages of Lake Placid, Tupper Lake and the surrounding area (referred to as the "Tri-Lakes area") in the late 1990s and early part of this decade placed increasing load on the electric assets in this region. The 115 kV and 46 kV transmission system assets serving the Tri-Lakes area are radial and the systems and the customers they serve are exposed to extreme weather and serious consequences exist if extended outages occur (e.g., some of the communities rely extensively on electric space heat). In addition, Niagara Mohawk uses its assets in the Tri-Lakes area to serve its retail customers; and, the New York Power Authority ("NYPA") relies on the Company's transmission facilities for the commodity service it provides to its wholesale municipal customers, Lake Placid and Tupper Lake. To improve the reliability of the system and ultimately improve the service to Niagara Mohawk and NYPA customers, both parties entered into an agreement to construct two new Static VAR Compensators (SVC), a 46kV SVC located at Tupper Lake, and an 115kV SVC located at Lake Colby. In addition to the voltage support facilities, the project included the construction of a new 46kV line from the Townline Substation to the Piercefield Substation.

Q. What are the commercial arrangements relating to the Tri-Lakes project?

A. Under the agreement reached between NYPA, the Company, the Village of Lake Placid and the Village of Tupper Lake on September 15, 2004, and revised October 24, 2006, NYPA agreed to own, finance and hold title to all of the facilities constructed until January 1, 2012 when the Company was expected to enter into a new rate plan. The construction of the new facilities has been completed and are now in service, and providing customers with enhanced reliability. The Company is proposing to purchase the assets from NYPA on January 1, 2011, one year earlier than anticipated, to coincide with the timing of the new rate plan and intent of the Tri-Lakes agreement.

Q. What is the financial effect of moving the buy-back up one year?

A. The earlier purchase would reduce the “buy back” price of the facilities by \$2.0 million. In addition to reducing the overall buy back cost, purchasing the assets early would also reduce the risk of litigation of the contract in the event of unforeseen circumstances which could occur, such as injury or damage of equipment.

Q, Is the $35 million payment for the Tri-Lakes project reflected in the Company's infrastructure investment budgets that the Panel described previously?

A. The $35 million payment amount is not reflected in the Company's infrastructure investment plan described previously; however, the payment is reflected in the Company's revenue requirements calculations as described above.

<u>Hydro One</u>

Q. Please describe the "Hydro One" project.

A. The Hydro One project relates to the replacement of a large transformer in which the Company has a direct interest. The Beck-Packard No. 76 Regulating Transformer ("BP76 Transformer"), which is owned by Hydro One and is located at Beck substation in Ontario, Canada, suffered a catastrophic internal fault on January 30, 2008. Hydro One conducted a rigorous post fault analysis and determined the asset could not be repaired, and would need to be replaced. The replacement costs of the transformer are projected to be approximately $9 million; actual cost will be dependent on the exchange rate at the time of purchase. The transformer regulates the flows on the Beck – Packard No. 76 line, and the line can not be placed back into operation without the regulating transformer in service.

Q. What is the Company's interest regarding the BP76 Regulating Transformer?

A. The Company and Hydro One have an Interconnection Facilities Agreement which manages the operation of the International Tie-line (Beck – Packard No. 76) and institutes the concept of an "Asset Owners' Committee" of which both Hydro One and the Company are members. The Asset Owners' Committee is required to agree prior to making many decisions which affect the tie-line including performing extraordinary maintenance or replacement of the BP76 Transformer. If the Asset Owners Committee agrees to replacement of, or perform extraordinary maintenance on, the BP76 Transformer, costs would be shared equally between the parties.

Q. Has the Company determined whether it makes economic sense to replace the transformer?

A. Yes. The availability of the Beck – Packard No. 76 tie-line can have significant economic implications on the region when combined with major outages. For instance, based on an economic analysis done by the New York ISO, if the transformer is not replaced and is combined with 345kV outages on the NYPA system, this would cause an estimated $44 - $78 million in congestion in the market. Based on the existing New York ISO tariff, Niagara Mohawk customers would contribute approximately $8.8 - $15.6 million to the congestion shortfall and all other New York customers would contribute the remaining $35.2 - $62.4 million. Based on the value to the Company's customers and the benefits to the region, the Company proposes to share the transformer replacement costs with Hydro One.

Q. What is the timing of the transformer purchase and proposed cost recovery?

A. Hydro One has recently advised the Company that it intends to order the replacement transformer once it receives notice of agreement to share the costs of the new transformer. The Company intends to make payment for its share of the transformer to Hydro One (currently estimated at approximately $4.5 million). To mitigate the impact on rates and provide reasonable rate stability, the Company proposes to amortize the transformer payment over three years, from the date of payment. The accounting treatment for inclusion of the Hydro One costs in the revenue requirements is described in the testimony of the Revenue Requirements Panel.

J. <u>Comparison to Prior Infrastructure Investment Plans</u>

Q. How do the levels of proposed infrastructure investment in this case compare to prior and current investment levels?

A. The Company's currently effective base rates were established pursuant to the Merger Joint Proposal ("MJP") approved by the PSC in Case 01-M-0075. These currently effective rates reflect an annual capital investment plan budget of approximately $143 million.

Coincident with experiencing declining reliability performance associated, in large part, from diminished performance of deteriorating assets reaching the end of their useful lives, the Company undertook reviews of the condition of its system and its assets, and has for several years been investing pursuant to the asset management approach in an effort to address the findings of those reviews. Those investments have been at levels far in excess of the investment levels provided in current rates.

As a result of reliability issues raised in the National Grid/KeySpan merger proceeding (Case No. 06-M-0878), the Company was directed by the Commission to invest at least $1.47 billion over five years in the Upstate New York electric system--an amount significantly greater than what is reflected in current rates.

Under the $1.47 billion investment requirement, the Company was to invest $255 million in FY07, $275 million in FY08, and $301 in FY09. Actual investment for this period has been $279 million in FY07, $284 million in FY08, and $318 million in FY09.

Q. Please explain why the Company has been investing at a pace even higher than the $1.47 billion requirement.

A. As explained in the October 22, 2007 Capital Investment Plan filing, while the Company committed to spend a minimum of $1.47 billion on transmission and distribution infrastructure, we also outlined a plan where capital spending necessary to attain the reliability metrics set for the Company would require $2.4 billion in investment. The expanded plan promotes the long-term reliability and sustainability of the network, and is in the best interest of customers. However, to date the Company has exceeded the $1.47 billion level. This additional investment and the investment outlined in this rate filing is the minimum necessary to meet mandatory obligations and near-term reliability without unacceptably increasing risk.

Q. How do the proposed investment levels for the rate plan period compare to prior planned investment levels the Company has submitted to the Commission?

A. The infrastructure investment plan present in this case is significantly reduced from the investment plan submitted last year. That plan totaled $3.57 billion for the 5-year period FY2010 to FY2014. In its most recent five-year plan (filed the same day as this rate case), the Company describes an investment plan that totals $2.86 billion ($2.95 billion with inclusion of Luther Forest Technology Campus and Tri-Lakes projects) for the five-year period FY2011 to FY2015.

Q. Why is the investment plan presented in this rate case lower than the investment level submitted to the Commission last January?

A. The Company's infrastructure investment planning process provides for on-going and continuous evaluation and refinement to reflect changed circumstances and new information. Thus, we are continually adjusting the plan to meet the needs of current and future customers in the most effective way possible. The current economic conditions facing our customers and the Commission's calls for austerity measures by utilities required identifying opportunities to defer or minimize spending where possible, consistent with our obligation to provide safe and reliable service. Thus, the infrastructure investment plan reflected in this case is designed to mitigate rate impacts on customers while also managing the near-term reliable performance of the system.

K. <u>System Planning</u>

Q. The management audit report included several recommendations relative to system planning. Could you provide a brief summary of the Company's system planning process?

A. Yes. As discussed previously, the Company's plans to implement the audit report recommendations, including those related to system planning, are described in the implementation plan included with Mr. Zschokke's testimony, in this case. However, in general, the Company's system planning process integrates two types of system assessment. The first type is system capacity planning, in which the ability of the Company's assets to handle customer loads and power flows is studied, extending out to a planning horizon 10-15 years in the future. Modeling programs are used to represent present and future conditions, for a variety of normal and contingency conditions. The models calculate power flows, voltages, dynamic performance, and fault currents. The modeling results are compared with planning standards and criteria to identify potential noncompliance situations. These assessments also address interconnection requests from customers, and ensure compliance with NPCC and NERC standards and criteria. They will generally lead to investments in the system in the Statutory/Regulatory or System Capacity and Performance categories of our investment plan.

The second type is an assessment of the physical condition and performance of the assets. This assessment yields important information about which assets should be given priority for replacement or refurbishment and considers factors such as degree and rate of deterioration, performance, criticality and the age the assets. Additionally, these assessments will look to improve reliability performance through the refurbishment or installation of new equipment such as reclosers or sectionalizing switches. Ensuring safety of both the public and employees, reliability of supply to customers, and protecting the environment are goals of this process. As discussed previously in detail, these assessments are done are in a number of ways including ongoing inspection and maintenance activities and targeted condition assessments.

These assessments can lead to investment in System Capacity and Performance and Asset Condition categories of our investment plan.

Both types of assessment are performed for all of the Company's electrical assets at all voltage levels, including transmission, sub-transmission, and distribution. To ensure that capital resources are utilized as efficiently as possible, the Company's planning process requires that asset condition planning and system capacity planning be coordinated with each other. Early in the process, both asset condition needs and system capacity needs in each area under study are identified and considered. Wherever appropriate, capital projects are sequenced and designed to address both types of system needs.

Niagara Mohawk's transmission system is extensively interconnected with the systems of other utilities in the Northeast U.S. To a more limited extent, there are also distribution interconnections. Full consideration is given to the effects of neighboring systems on the Company's system, and to the effects of Niagara Mohawk's plans on its neighbors. The Company participates in the planning processes of the NPCC and the NYISO, as well as other interregional planning initiatives.

L. Capital Investment Reconciliation Mechanism

Q. Is the Company proposing a mechanism to reconcile its actual capital expenditures with the level of capital recovery authorized in the rates approved by the Commission?

A. Yes. The Company is proposing to track its actual annual capital investment expenditures, including those associated with third party actions, against the target capital budget authorized by the Commission in this case, and to reconcile the difference annually.

Q. Why does the Company believe it needs a capital tracker?

A. The Company has a commitment to provide safe, reliable, environmentally sound service at a reasonable cost to customers. As discussed previously, the need for investment in the Company's infrastructure is significant and is increasing, and the infrastructure investment budget and associated O&M costs presented in this case are substantial. A tracker would protect customers in two ways. First, it would ensure that customers pay the appropriate amount. To the extent that actual investment falls short of the level forecasted by the Company, customers would receive a rate credit. Second, however, the proposed budgets in this case have been reduced from optimum levels in order to mitigate rate impacts on customers in light of the economic downturn, while still enabling the Company to sustain reliability over the near-term. Establishing a limited tracker (capped at 10 percent of the approved annual budget level) will provide the Company with necessary flexibility to respond to unforeseen circumstances that may warrant significant capital investments that are in the best interest of customers. It would eliminate any disincentive to do the right thing on behalf of customers due to the lack of a rate mechanism to recover such prudently incurred costs during the rate plan period in order to provide service.

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In addition, due to the interconnected nature of the New York transmission system, as Transmission Owners ("TO") replace or upgrade aging infrastructure and make reliability improvements on their systems, projects can have spillover effects on neighboring systems, not all of which are known and measurable by the Company at this time. For instance, in order for one utility's project to be put into service, the completion of related upgrades on a neighboring system may be required. If another utility's activities trigger investment needs or unanticipated reliability upgrade investments on the Company's system, and it is appropriate to put the costs of these unanticipated upgrades into the Company's rate base (because they provide benefits to the Company's own customers), the proposed tracker mechanism would provide for recovery. Conversely, to the extent it is appropriate that the Company enter into an agreement to fund upgrades on a neighboring utility system arising from the Company's investments (e.g., if it is not appropriate for the neighboring utility to put the costs into its own rate base), the proposed tracker mechanism would provide for recovery of those costs. The tracker mechanism is designed to provide flexibility and ensure timely recovery of costs associated with the spillover effect of neighboring TO's investment plans, and to enable required investments to proceed without delay. In light of the fact that the Company does not have control over spillover effect of neighboring TO's investment plans, we are proposing a limited exception to the 10 percent cap as explained in the testimony of the Revenue Requirements Panel.

Q. How would the capital tracking mechanism work?

A. The design and mechanics of the reconciling capital investment tracker are set forth in the testimony of the Revenue Requirements Panel.

V. <u>Facilities, Properties and other Capital Investments and Lease Costs</u>

Q. Please provide an overview of the Company's approach to property management.

A. The Company's property-management strategy is designed to meet customer service needs effectively and efficiently. In conjunction with the merger with KeySpan, the Company reviewed of all of its property holdings and those of the former KeySpan organization to consider the potential benefits to be achieved from consolidations and other improvements in the way in which the companies manage their facilities and deliver services to customers. As a result of that review, the Company determined that closing certain facilities and consolidating operations into others would achieve long term cost reductions and improve the efficiency with which it serves its customers. The Company also seeks to reflect its environmental commitment in the design and selection of its locations.

The plans described below provide potential cost savings by reducing the number of facilities the Company operates, and provide an opportunity to increase workforce productivity through co-locating employees who perform related functions together and changing the manner in which its workspaces are utilized. However, perhaps more important is that the facilities plans described below are critical and integral elements of the Company's broader Transformation initiatives we discussed previously, that are being undertaken to deliver even further benefits for customers. To that end, this testimony focuses on the Company's proposed property related capital and lease expense changes related to facilities for the rate plan years.

Q. What parameters does the Company take into account in its review of its facilities?

A. The Company reviews its properties on an ongoing basis to ensure they continue to serve its customers effectively and efficiently. In undertaking any review, the Company looks at customer response, proximity to planned work, anticipated growth, opportunities to co-locate functions, and financial costs and benefits including: ongoing operating costs, anticipated capital investment and potential disposition proceeds. Through this economic and qualitative analysis, the Company has initiated property consolidations and respective investments that will achieve long-term benefits to its customers.

Q. You indicated that the Company's efforts to consolidate facilities include a focus on integrating business teams. How is this reflected in the Company's decision-making process for consolidating facilities?

A. In addition to considering economic factors as part of the property consolidation process, the Company considers several qualitative criteria to guide its decision-making process:

- Office workers should be consolidated into as few locations as possible;
- Large, end-to-end processes should be physically co-located in a single facility, where possible;
- Managers should be located with their manager or work group when possible, preferably both;
- Critical infrastructure facilities should be in fewer locations;
- There should be no more than one office or workstation per employee; and
- Lower-cost facilities and low-cost, off-site storage should be utilized to the maximum extent possible.

Although we describe these as "qualitative" criteria, they obviously have a significant impact on the efficiency and effectiveness with which the Company delivers service to customers, and, therefore, ultimately do have a financial impact.

Q. Please provide an overview of the kinds of facilities the Company uses to provide service to its customers.

A. The Company's Property Services group oversees the maintenance and operation of 55 occupied locations: a main office location at Syracuse (approx. 467,000 sq. ft), six specialty/non-operating sites including warehouses and an airport hangar (155,000 sq. ft), and 48 operating sites (approximately 2,213,000 sq. ft) which house its physical work force, fleet operations, warehouse and other field support groups.

Q. Please describe the Company's facilities-related capital investments reflected in the revenue requirements in this rate case.

A. The levels of planned capital investments in properties and facilities are set forth in Exhibit __ (RRP-6), Schedule 1, Sheet 4, of the Revenue Requirements Panel's testimony, and are approximately \$36.4 million in FY11, \$32.4 million in FY12, and \$4.4 million in each of FY13 and FY14. These capital investment amounts include a base level of spend in each of the years in the rate plan period (\$3.9 million in FY 2011, and \$4.4 million in each of FY12 – FY14), as well as investments associated with seven specific major facilities projects. These seven projects are: (1) the Syracuse Office Complex ("SOC") façade; (2) the SOC interior renovation; (3) the North Albany Renovation; (4) the Henry Clay Boulevard ("HCB") Control Center Consolidation; and separate consolidation projects in (5) the Saratoga area; (6) the Syracuse area; and (7) the Buffalo area.

Q. Please describe the basis for the baseline facilities capital dollars.

A. The baseline facilities capital expenditures are allocated for capital projects associated with the maintenance of facility assets. The capital projects are comprised of projects that are designed to enhance the safety, security and infrastructure at facilities. The majority of safety related projects are made up of upgrades to life safety systems within facilities. For example, numerous facilities require upgrades to the fire alarm systems to provide adequate warning for employees in the event of a fire. Pavement replacement projects also fall into the safety category of spend. The pavement at many of our facilities has exceeded its useful life. Significant cracking and potholes have lead to dangerous conditions for our employees. Uneven walking surfaces can lead to slips, trips and falls particularly in the winter months when these areas tend to accumulate water and form ice.

Infrastructure improvement projects are intended to replace or enhance the life of an existing asset. Such projects include, but are not limited to, roof replacements, HVAC replacements, system upgrades and electrical upgrades within a facility. Many of the roofs across the system have exceeded their useful life with some over 50 years old. Leaking roofs can lead to water damage within facilities including the potential for mold growth. Many HVAC units have also exceeded their useful life and require replacement because many of the parts required to repair the units are no longer available and in many instances it is more economical to replace a unit than to make repairs.

Security projects intended to enhance the security at our buildings including, fencing, gates, card readers and video surveillance equipment are also included in the asset maintain category.

Q. How are the baseline capital expenditure estimates derived?

A. The baseline capital expenditure level is based on historical levels of spend as outlined in Exhibit__ (IOP-5), Schedule 1.

Q. How were the capital estimates for the larger projects included in the Company's facilities plan developed?

A. Initially, the Company uses historical data on its own projects or similar projects undertaken in other regions of its business. Preliminary estimates may be developed using external commercially available estimating firms. As a project evolves from conceptual to preliminary to the detail design phase, the Company will employ outside architects, engineering firms, specialist contractors or general contractors to develop and refine the details and scope of work. In any procurement of an outsider service, the

Company's property team will follow the appropriate procurement procedures to ensure the most cost effective services are obtained for its customers and business.

Q. Please describe the Syracuse Office Complex façade project.

A. The Syracuse Office Complex ("SOC") main building is one of the finest examples of art deco architecture in Upstate New York. Completed in 1932, the building has been a source of civic pride for many decades. The ongoing SOC façade project involves replacement of multiple roofs, including limited stone replacement. Work on upper level exterior windows and building front, and stone work to address weather and water damage, is also included.

Q. What are the benefits of the SOC façade project?

A. This building is over seventy years old and such reconstruction is often required. The benefit of this work is safety related as certain stone pieces have dislodged, and, within the building, the Company has been experiencing various water leaks and interior damage. The work began in 2009 and is ongoing and anticipated to be completed by December of 2011.

Q. What costs are reflected in the Company's plan for the SOC facade project?

A. The budgeted costs for the remaining work to complete the SOC façade renovations are reflected in Exhibit __ (IOP-5), Schedule 2. The project totals $8 million for the period February 2007 through December 2013, of which $6.8 million is allocated to electric and $1.2 million to gas. All of the costs associated with the SOC project are reflected as capital costs.

Q. Please describe the Syracuse Office Complex interior renovations project.

A. As part of its overall property strategy, the Company affirmed its commitment to maintain the Syracuse Office as one its main offices. The ongoing renovations are to accommodate business consolidation related to support of the TDC (Transaction Delivery Center) referenced in Mr. Andrew Sloey's testimony and Transformation initiatives which are described in other parts of this testimony and will allow an expansion from 1,530 occupants to 2,100 occupants at completion. Some of the renovations were begun in 2008 and 2009, but will be done on a more broad scale in 2010 and 2011. The project includes room reconfigurations, new office equipment, office areas, seating and walkway area renovations, paint, carpet, and furniture replacement and reconfiguration. The work is ongoing and anticipated to be completed by August 2011. A reduction of expenses will result from the expiration and non-renewal of the “E” building lease (2011) at the SOC. In addition, the parking lease for an area near the SOC expires in CY 2013 and will not be renewed resulting in additional savings. Both leases and corresponding reductions are reflected in the Company’s revenue requirement.

Q. What benefits are achieved from the SOC interior renovation project?

A. The Company is consolidating certain functions as well as establishing a new Transaction Delivery Center which will result in improved service delivery to customers, and improve the overall efficiency of its work practices. The investment is also good for the local community by solidifying the Company’s presence in Syracuse.

Q. What costs are reflected in the Company's plan for the SOC interior renovations project?

A. The budgeted costs for the remaining work to complete the SOC interior renovations are listed in Exhibit __ (IOP-5), Schedule 2, and total $20 million covering the period October 2009 through December 2013 of which $17 million is allocated to electric and $3 million to gas. All of the costs associated with the SOC interior renovations project are reflected as capital costs.

Q. Please describe the Henry Clay Boulevard Control Center ("HCBCC") project.

A. The Company currently has three electric distribution control centers in New York: one in Buffalo, another in Liverpool and a third in Guilderland. The Company proposes to consolidate the three control centers into a single, centralized control center in Liverpool.

Q. Why is the Company proposing to consolidate its control centers?

A. The objective of the consolidation is to improve operational performance across the Company. This would be achieved by developing new roles, responsibilities and work flow segments that are aligned with a newly designed control room. The new control room would take advantage of industry best practices and new systems, visual displays, versatile control room consoles, more accurate outage reporting, standardized outage restoration practices, process standardization, and improved operator training at one central location. The overall goal is to provide control room employees with new tools that result in better situational awareness and decision making in the management of the distribution system.

Control center consolidation will also yield efficiency and operational improvements. For example, centralizing the management of storm response in a consolidated control center in Liverpool reduces the number of times field offices need to be opened to support the dispatch and assignment of outage calls associated with small and medium scale events, and enables more effective use of clerical and design personnel that have been centralized in Syracuse at the Syracuse Office Complex. A consolidated control center will also bring together highly technical personnel in an environment that fosters the sharing of best practices and provides a consistent means of managing and operating the distribution system.

In addition, the consolidated control center will work in conjunction with a similarly consolidated control center in Northborough, Massachusetts. The implementation of the same technologies used by personnel within both centers will allow for the sharing of best practices and the ability to 'back each other up' in the event of an evacuation of a control center or to provide additional personnel to assist customer restoration in response to a major event.

Q. When is the control center consolidation planned to take place and what costs are associated with the project?

A. The Company plans to start construction on the consolidation in September 2010, with a target completion date of May 2012, and estimated capital costs of $13.5 million. Of the total amount, $11,475,000 is allocated to electric and $2,025,000 to gas. In addition, approximately $100,000 would be incurred in 2010 in preparatory work.

Q. Please describe the Syracuse area project.

A. The Syracuse area project also involves the Henry Clay Boulevard (HCB) site. The Syracuse area project will support renovation and consolidation of operating locations resulting in improved efficiency. The Company intends to close its leased facility at Beacon North in Syracuse and consolidate the operations there into its owned operating facility at Henry Clay Boulevard, thereby reducing the number of operating facilities. The Syracuse area project, scheduled to commence in April 2010 and to be completed in March 2011, will include renovations and building new facilities to accommodate movement in personnel, vehicles and material to HCB to accommodate a consolidation of electric and gas personnel at the site including crew rooms, meeting areas, storage, warehousing, yard and parking.

Q. What benefits are anticipated by consolidation of operation sites in the Syracuse area?

The Beacon North facility is leased and represents a significant ongoing operating cost to the Company. With its closure, these costs will be eliminated. The Company will see reductions in annual operating expenses including maintenance, janitorial, landscape, snow removal plus avoid capital investment. Further, the Company expects to gain improved workforce efficiencies, including improved training opportunities where a large concentration of its physical workforce will now have close proximity to training facilities.

Q. What costs are reflected in the Company's plan for the Syracuse area project?

A. The costs for outstanding work to complete the Syracuse area project are listed in Exhibit __ (IOP-5), Schedule 2, and total $10.0 million covering the period January 2010 through December 2013 of which $8.5 million is allocated to electric and $1.5 million to gas. All of the costs associated with the Syracuse area project are reflected as capital costs.

Q. Please describe the North Albany renovation project.

A. The North Albany renovations are to accommodate office needs for identified consolidation opportunities for the Company's operating facilities in the Capital region. The Company intends to consolidate its two Troy, New York locations and a single site at Glenmont, New York into its existing North Albany facility. A small crew facility will be maintained in the Troy area to ensure adequate response times for customers east of Troy. The North Albany project will improve utilization of shared facilities such as warehousing, yard and meeting space. The renovations will include required fit-outs, parking improvements, room renovations, storage upgrades, locker facilities, and utilities as required. The plans for the renovations are currently under development and may also include exterior work as needed. The renovations are scheduled to start in December 2009 and are anticipated to be completed by August of 2011.

Q. What are the benefits of the North Albany consolidation project?

A. The benefits from the North Albany project include: reductions in annual operation expenses such as maintenance, janitorial, landscape, snow removal; avoided capital maintenance, and property tax savings from the closure of the Troy and Glenmont sites. The Company expects to gain improved workforce efficiencies including: improved training opportunities, more flexibility to schedule work over a broader area, improved utilization and sustained or improved service to customers through the integration of its crews. The Company will also undertake improvements to its warehousing and materials storage practices, as well as environmental remediation work at the same time to ensure efficient scheduling of work and spending on this project. Finally, sale or lease of the Troy and Glenmont sites may produce proceeds on disposition.

Q. What costs are reflected in the Company's plan for the North Albany renovations project?

A. The costs for outstanding work to complete the North Albany project are listed in Exhibit __ (IOP-5), Schedule 2, and total $8.25 million covering the period from October 2009 through December 2013 of which $7,012,500 is allocated to electric and $1,237,500 to gas. All of the costs associated with the North Albany project are reflected as capital costs.

Q. Please describe the Saratoga area project.

A. The Company currently occupies two leased facilities, one at Weibel Avenue in Saratoga and another in Glens Falls. The Company’s lease for the Weibel Ave location was not extended by the landlord beyond the current term (which ends October 2011) and the Company needs to replace this location. The project will renovate or build a new operating location in the Saratoga area. The Saratoga area project is scheduled to commence in August 2010 and be completed by November 2011, and will include consolidating some personnel from the Glens Falls location.

Q. What are the benefits of the Saratoga area project?

A. The Company has enjoyed the benefit of its relatively low cost, leased facility at Weibel Avenue in Saratoga to service this area. The Company does not have the option to extend its terms beyond October, 2011. With a strong continuing need to serve its electric and gas customers in the area, the Company must replace this facility location to ensure continued safe and efficient service its customers, alignment to its business model and flexibility to meet anticipated future growth.

Q. What costs are reflected in the Company's plan for the Saratoga area project?

A. The costs to complete the Saratoga area project are listed in Exhibit __ (IOP-5), Schedule 2, and total $10 million covering the period from January 2010 through December 2013 of which $8.5 million is allocated to electric and $1.5 million to gas. All of the costs associated with the Saratoga area project are reflected as capital costs.

Q. Please describe the Buffalo area project.

A. The Buffalo area project will involve closing the Company owned Tonawanda facility and consolidating the operations and personnel there into existing Company owned facilities at Dewey, Kensington and Niagara Falls. The project will include all necessary renovations to the Dewey, Kensington and Niagara Falls facilities to accommodate consolidation of the Tonawanda operations, including fit-outs to accommodate people and equipment. The work is scheduled to commence in June 2010 and to be completed in November 2010.

Q. What are the benefits to be achieved from the proposed consolidations of the Buffalo area project?

A. The benefits achieved by the Buffalo area project include reductions in annual operation expense such as maintenance, janitorial, landscape, snow removal as well as avoided capital improvements and property tax savings through closure of the Tonawanda site. Further, the Company expects to gain improved workforce efficiencies, including improved training opportunities, more flexibility to schedule work over a broader area, improved utilization and sustained or improved service to customers through the integration of its crews. In addition, the Tonawanda site will be marketed for sale or lease which will result in potential disposition proceeds.

Q. What costs are reflected in the Company's plan for the Buffalo area project?

A. The costs for outstanding work to complete the Buffalo area project are listed in Exhibit __ (IOP-5), Schedule 2, hereto and total $2.0 million covering the period January 2010 through December 2013 all of which is allocated to electric. All of the costs associated with the Buffalo area project are reflected as capital costs.

Q. Please describe the new facility at Reservoir Woods and its benefit to the Company's customers.

A. Early in the process of the integration of KeySpan and National Grid, National Grid determined to consolidate its main office space to support its customers. After considering leasing or purchasing space at a number of locations, National Grid decided to lease a new facility at Reservoir Woods located in Waltham, Massachusetts.

Q. What support to Niagara Mohawk customers is based at Reservoir Woods?

A. The Reservoir Woods facility provides shared services functions such as general corporate support, human resources, legal, and regulatory as well as functions related to the New York transmission and distribution electric system including:

- Distribution and Transmission Asset Management- management of strategic objectives relating to New York transmission and distribution assets, network performance and business targets for New York;
- Capital Program Management – managing programmatic type of work and developing resource allocation plans;
- Project and Construction Management - management of the New York based project managers;
- Operations and Maintenance – management of the New York divisions for O&M; and
- Operations Performance Reporting - network performance reporting, circuit event analysis, control centers policies, systems and operational objectives.

Q. How are the costs associated with the Reservoir Woods facility reflected in the Company's revenue requirements in this case?

A. Niagara Mohawk's portion of the costs of the Reservoir Woods facility is reflected in the Revenue Requirements Panel's Exhibit __ (RRP-2), Schedule 8.

Q. Are there any other facility closures reflected in the Company's rate year filing?

A. Yes, the Star Lake facility has been closed and its lease will not be renewed. Similarly, a leased facility at Federal Street in Saratoga, has already been closed. Reductions in lease expense of $5,500 and $165,000 per year respectively are reflected in the Company's revenue requirements for the rate plan years.

Q. Please describe the capital investment of $0.6 million per year related to fleet services, inventory management and investment recovery.

A. For the rate plan period, Fleet Services plans annual capital expenditures of approximately $0.4 million for items such as: diagnostic software/hardware, Hetra columns, lift replacements, fuel pump upgrades, cabinets, tool boxes, and other miscellaneous garage tools and equipment. The Company also projects annual capital expenditures of approximately $0.2 million in the inventory management and investment recovery areas relating to things such as hand held devices and "carousel software," which are used extensively for warehouse tracking materials of materials.

VI. Information System Investments

Q. Is the Company proposing any information system ("IS") investments that affect electric system infrastructure or operations?

A, Yes. As reflected in Exhibit __ (IOP-6), the Company is implementing several such IS initiatives that affect the Company's electric infrastructure and operations, resulting in IS expense that is incremental to the historic test year of $1.5 million in CY 2011, $2.1 million in CY 2012, and $6.5 million in CY 2013. In addition, the Company will be implementing a new Energy Management System ("EMS"), which will include a capital investment of $20.1 million over the period FY11-FY14.

Q. Please describe some of the major electric infrastructure and operations IS initiatives the Company will be implementing.

A. The most significant IS projects affecting electric operations are the Distribution Management System and Outage Management System, the Mobile – Electric Distribution Grid Mobile Expansion, the Transformation Key Performance Indicator ("KPI"), and the Radio Console Standardization projects.

Q. Describe the Distribution Management System and Outage Management System project.

A. The Distribution Management System (DMS) and Outage Management System (OMS) project will offer several significant benefits to Niagara Mohawk customers. First, the version of the Outage Management System (General Electric PowerOn) currently in use by the Company has not been updated to the latest version, and is no longer fully supported by the vendor. The risks associated with providing adequate support of PowerOn continue to grow and will be resolved with implementation of the new OMS. Second, an updated OMS system will allow for the implementation of DMS functionality which will maximize control room expertise and efficiency with regards to safety, reliability and productivity. It will also allow standardized training and operator development and streamlined processes and procedures (including minimizing/eliminating the use of paper maps, reducing manual processes, and creating one, current view of the network model available to all necessary resources). Further, the addition of a DMS is critical to moving forward with a fully functional Smart Grid program. Lastly, the Company is working with ABB (vendor) on integrating DMS/OMS with an upgraded EMS system that will substantially improve our ability to ensure the reliability of the electric network as well as our ability to quickly restore service in the event of an outage. All of these new systems (DMS/OMS/EMS) will add functionality that will allow more automated network switching in our network control centers. The Company's planned EMS system investment is described later in our testimony.

Q. What are the costs associated with the DMS/OMS project?

A. The costs of the OMS/DMS will be shared among the National Grid operating companies that use the system. The total cost of the OMS/DMS is $30 million, and it is to be amortized over 5 years from its in-service date, now expected to be April 2013. Niagara Mohawk's share of OMS/DMS costs in 2013 will be $2.534 million. Derivation of these costs and the allocation to Niagara Mohawk is addressed in the Revenue Requirement Panel's Exhibit __ (RRP-2), Schedule 8.

Q. Describe the Mobile – Electric Distribution Grid Mobile Expansion project.

A. Many electric operations field workers in the Niagara Mohawk service territory are not equipped with mobile computers. This project will provide that equipment and enhanced capabilities and functionality. The ability to access work management and other applications online from the field will significantly improve both the accuracy and timeliness of information collected in the field, will improve timely and accurate responses to outages, ensure that the most up to date safety procedures are available to working field crews, and support more efficient use of or reductions in clerical staff. Examples of field transactions that will be supported by this project include the ability to dispatch trouble orders directly from the OMS to field crews for initial and follow-up work, real time access and update capability to the geographic information system (GIS), and online capture of field construction design and "as-built" information. In addition, status of customer work in the field will be captured and updated in the customer system (CSS) so that the information will be readily available to contact center personnel in their discussions with customers. This investment will include the implementation of the required hardware, telecommunications and software. Start-up costs are required for FY2013 with implementation beginning in FY 2014, therefore the benefits identified will be realized and incorporated into future rate cases.

Q. Describe the Radio Console Standardization project.

A. The radio console equipment in our Electric Distribution Control Centers and Transmission Control Center is well beyond normal end of life. It is no longer supported by the vendor (Motorola), and the risk of continuing to operate this equipment is unacceptable. Replacement parts are largely unavailable from the vendor. The radio console equipment is the primary means of communication between the control centers and field crews, and its reliability is critical to crew safety and to ensuring timely repairs to the electric distribution and transmission system.

Q. Describe the Transformation Key Performance Indicator ("KPI") project.

A. The Transformation Program is a major initiative designed to implement a new operating model that is introducing best practices across a number of work streams. A key element in this transformational program is the ability to measure the performance of the new operating model through relevant measures and detailed metrics. The Transformation KPI project establishes a framework and centralized solution that allows the company to draw information from a number of operational systems and create scorecards at all levels of the organization to display performance against those metrics to the individuals responsible for the work and to their management. This investment allows us to deliver specific reporting, measures and scorecards, as outlined during the PSC Management Audit, specifically the 29 value measures for productivity. This KPI capability was supported by the PSC Management Audit, and is established as an assumption for delivery of specific recommendations surrounding performance management and work management. This investment will allow electric operations senior management to have visibility into the performance of the organization and highlight potential problem areas to ensure that we are optimizing service to Niagara Mohawk customers. In addition, the KPI project will also enable regulatory reporting of the Company's performance and service to customers and provide a basis by which to benchmark against peer utilities.

Q. Please discuss the new Energy Management System ("EMS") the Company will be implementing.

A. The EMS replacement project is a combined transmission and distribution project. The EMS system is used for monitoring, control and operation of the transmission and distribution electrical system. The current EMS system is 23 years old and the vendor, Stagg Systems, is no longer in business. Therefore, vendor support and upgrades are no longer available. The planned investment in new operator workstations and primary and back-up servers will allow the Company to follow a 4-6 year refresh cycle that is in line with current industry practice.

This investment modernizes the EMS to mitigate reliability risks associated with the loss of system control and situational awareness of the electric system and will insure information and data is exchanged with the regional Independent System Operators and transmission owners. The implementation of this project will coincide with the DMS/OMS system upgrades described previously. The total capital investment cost for the EMS replacement project is $20.1 million, with $13.0 million associated with transmission and $7.1 million associated with distribution. Implementation of this project began in May 2009 and will continue through the end of 2012.

Q. Is the Company undertaking other operations-related IS projects that are reflected in the rate case revenue requirement?

A. Yes. In addition to the projects described above, the company has a number of smaller yet very important projects in the electric operations area that will improve the customer experience and help reduce operating costs. These projects, and their associated costs, are listed in Exhibit __ (IOP-6).

VII. Operations and Maintenance Expenses

Q. Please describe generally the nature of the Company's electric system operations and maintenance expenses.

A. Operations and Maintenance (O&M) expenses relate to work performed specifically for the purpose of preventing failure, restoring serviceability, or maintaining the life of capital assets. Niagara Mohawk has a significant maintenance program implemented with the goal of ensuring the assets installed on the system can be utilized to their fullest potential life expectancy. However, due to the current physical condition of many assets, the Company is likely to experience increases in maintenance costs until these assets can be replaced. These costs include such things as increased costs for more frequent inspection and testing, more significant repair costs (e.g. major overhaul of circuit breakers versus standard minor work), and costs for emergency work. These expenditures are required to prevent failure and maintain the life of the assets until replacement occurs.

Reduced inspection cycles are warranted if it is determined that an asset cannot last until the next normal inspection. One example would be increasing the frequency of Dissolved Gas Analysis (DGA) performed on power transformers when scheduled maintenance test results indicate deterioration has occurred within the main tank of the transformer or the Load Tap Changer (LTC).

Q. What is reflected in the Company's rate case filing relating to O&M expenses for the electric transmission and distribution system.

A. As described in the testimony of the Revenue Requirements panel, the Company's total electric operations and maintenance ("O&M") expense for the rate years 2011, 2012 and 2013 is $1,112.5 million, $1,114.5 million, and $1,114.5 million, respectively. These amounts are presented in detail in Exhibit __ (RRP-1), summary schedule, to the testimony of the Revenue Requirements Panel.

Q. How do the rate plan expense levels presented in this rate case compare to the historic test year expenses for operating the T&D System?

A. For the historic test year ending September 30, 2009, the Company's adjusted electric O&M expense was approximately $898.9 million, as set forth in Exhibit __ (RRP-2), Schedule 45 of the Revenue Requirements Panel.

Q. Please describe those adjustments needed to the historic test year electric operating expense necessary to arrive at the proposed rate year expense.

A. There are several known or anticipated changes in the Company's rate year expense levels from what the Company incurred during the 12-month test year period of October 2008 – September 2009. Many of these changes are addressed in the testimony of the Revenue Requirements Panel. In our Panel's testimony, however, we provide additional detail with respect to several of the known and measurable cost changes totaling approximately $81.2 million reflected in the Company's rate filing in this case, including:

- costs of mandatory and enhanced inspection and maintenance requirements;
- transmission tower painting costs, and comprehensive aerial inspection costs;
- costs associated with changes to the Company's vegetation management program;
- operating expenses associated with the increased levels of infrastructure investment;
- changes to the current mechanism for recovering extraordinary storm expense; and

- increased costs associated with site investigation and remediation activities.

Taken together, these changes account for approximately $81.2 million of the difference between the Company's historic test year expense and forecast rate year expense in 2011.

In this part of our testimony, the panel also addresses the status of the Company's service quality performance program.

A. <u>Inspection and Maintenance</u>

Q. Please describe the Company's proposal in regard to increased O&M costs to the inspection and maintenance program as a result of the 2008 Safety Order

A. Pursuant to the 2008 Safety Order, the PSC directed utilities to undertake enhanced inspection and maintenance activities on their electric system. These activities included additional elevated voltage testing requirements, and the establishment of specific timeframes for the remediation of deficiencies identified as part of a utility's system inspection activities.

Q. Could you describe the nature of the additional elevated voltage testing requirements in the 2008 Safety Order?

A. In the 2008 Safety Order, the PSC adopted changes to its electric safety standards to require that all utilities serving cities with populations of at least 50,000 (based on the 2000 census) conduct a mobile elevated voltage detection survey of their underground electric distribution system in those areas. The initial survey was to be completed during calendar year 2009, with annual surveys to follow thereafter. Based on their populations, the Company is required to conduct an annual mobile elevated voltage survey in Buffalo, Niagara Falls, Syracuse, Utica, Albany and Schenectady.

Q. What costs are associated with the new mobile testing requirement?

A. The Company estimated the annual costs at approximately $5.4 million. This amount includes the use of a certified mobile test vehicle and additional contractor costs to “stand by” locations identified to be above the relevant elevated voltage threshold.

Q. What is the basis for the Company’s estimated costs of the mobile test vehicle and contractor stand by resources?

A. The Company’s estimate of approximately $5.4 million per year is based on actual contractor costs experienced in 2009. The Company completed the first annual survey of the six cities mentioned above as of December 2009.

Q. Does the 2008 Safety Order require enhanced remediation efforts by utilities?

A. Yes. In the 2008 Safety Order, the PSC directed that utilities are required to mitigate all elevated voltage findings of 1 volt or more. Previously, utilities (including the Company) were required to take corrective action to mitigate elevated voltage findings of 4.5 volts or greater.

Q. What impact does the Company project the tightened standard will have on its elevated voltage activities?

A. For elevated voltage findings between 1 and below 4.5 volts, the Company will act to cordon off the affected area (e.g., using cones, barricades or warning tape) to indicate the existence of a possible safety hazard. Under PSC requirements, once the area has been cordoned off, the Company is to return as soon as practical to mitigate such findings.

The Company will also continue to mitigate elevated voltage situations of 4.5 volts or more. Because the higher potential creates greater concern, these mitigation efforts will require the protection of the area (e.g., by posting utility or contractor personnel) until repair crews arrive to repair the situation and make the location safe.

Q. What is the Company's estimate of the costs of complying with the mobile test requirement in the 2008 Safety Order?

A. In addition to the approximate $5.4 million in vendor costs for the certified mobile test vehicle and stand by contractors described above, the Company estimates that it will incur approximately $1,180,000 annually in additional expense associated with complying with the reduced voltage requirements from the 2008 Safety Order. This estimate is based on the number of elevated voltage locations identified in the field by the test vehicle in Buffalo during the first few weeks of testing, a typical repair cost, then extrapolated across the system. The cost of the test vehicle plus repair costs brings the total estimated annual incremental O&M expenses associated with these activities to $6.58 million.

Q. Is it possible the estimated costs to repair deficiencies located by mobile testing will vary from the $1,180,000 you mentioned above?

A. Yes. The Company has only recently completed the mobile test initiative, and the estimate was based on a relatively small sample of repairs. More recent information developed following the estimate reflected in this rate case suggests the actual annual repair costs could be higher than $1,180,000. The Company will seek deferral treatment of any charges in excess of $1,180,000. The actual program costs through December 31, 2009 were previously submitted in a report to Staff dated January 15, 2010, a copy of which is included in Exhibit __ (IOP-7).

Q. Are there other requirements stemming from the 2008 Safety Order that affect the Company's projected rate year expenses and that are not reflected in the historic test year?

A. Yes. In addition to the mobile testing and reduced voltage requirements described above, the Commission established a condition-based schedule for addressing deficiencies identified by utilities when they conduct their annual system inspections. Specifically, the PSC established four priority categories of deficiencies (as described in Appendix A to the 2008 Safety Order):

Level I – repair as soon as possible, but not longer than one week. A Level I deficiency is an actual or imminent safety hazard to the public or poses a serious and immediate threat to the delivery of power. Critical safety hazards present at the time of the inspection shall be guarded until the hazard is mitigated.

Level II – repair within one year. A Level II deficiency is likely to fail prior to the next inspection cycle and represent a threat to safety and/or reliability should a failure occur prior to repair.

Level III – repair within three years. A Level III deficiency does not present immediate safety or operational concerns and would likely have minimum impact on the safe and reliable delivery of power if it does fail prior to repair.

Level IV – condition found but repairs not needed at this time. Level IV is used to track atypical conditions that do not require repair within a five-year timeframe. This level should be used for future monitoring purposes and planning proactive maintenance activities.

Q. What is the impact of the Commission's order on the Company's projected costs during the period covered in this case?

A. The revised requirements of the 2008 Safety Order have effects on the Company's future operations expense as well as on its infrastructure investment plan. First, Level I deficiencies must be addressed as soon as possible, and it is the Company's expectation that the costs associated with those efforts will be primarily expense-related. The Company does not project a specific increase over historic test year spending.

Level II deficiencies, which must be addressed within 12 months of identification, are expected to lead to remediation efforts which will be more evenly balanced between expense activities and capital expenditures. Because the 12-month timeframe for addressing Level II deficiencies has the effect of advancing some of the Company's projected capital and maintenance spending, the rate case spending projections are greater than what is reflected in the historic test year.

Finally, Level III deficiencies would need to be addressed within 3 years. Typically, Level III-type of situations would be less likely to be addressed through maintenance activities, and instead more likely to be remedied through capital expenditures. Level III work typically will enhance the reliability of the system but is not required to maintain it at present levels. Examples of such work include: poles, cross-arms and other capital assets that are deteriorated but still have sufficient life that they do not pose an imminent risk to public safety or reliability prior to the next five-year inspection cycle; replacement of missing animal guards; repair of equipment bonds; and addition of lightning arresters at conductor transitions and feeder open locations such as feeder ties and at the end of circuits to improve lightning performance. Because of the required 3-year remediation timeline established in the 2008 Safety Order, the Company's infrastructure investment plan presented in this case reflects an increased amount associated with projected capital investment related to Level III projects.

Q. What incremental costs are associated with implementing the 2008 Safety Order you mentioned previously?

A. The incremental capital investment necessitated by the 2008 Safety Order is described previously in this testimony as part of the description of the infrastructure investment plan. In addition to the estimated capital investments (and O&M expense related to those capital incremental as described later in our testimony), the Company will incur additional O&M expenses to address issues identified as part of its inspections program. The Company estimates these additional O&M expenses will be $2.65 million in CY11, $2.7 million on CY12 and $710,000 in CY13. The expense is lower in CY13 because the Company anticipates that Level II remediation work will decline after one full five-year cycle of inspection and maintenance under the new criteria is completed. Exhibit __ (IOP-8) provides a calculation of these estimated costs.

Q. Please describe the Company's proposal with regard to its non-mandatory enhanced inspection and maintenance program costs that are incremental to the requirements of the 2008 Safety Order.

A. In addition to the incremental work that will result from the 2008 Safety Order, the Company is also undertaking additional non-mandatory enhanced inspection and maintenance initiatives intended to help improve the safety and reliability of the electric system, as well as the efficiency of performing its inspections and maintenance programs. These initiatives include infrared inspections of pad-mounted transformers and hand holes to identify defective or loose cable connections before they fail. Additional "fast" distribution feeder patrols of mainlines are intended to identify conditions in the field that may lead to an imminent outage. Finally, enhancements to the inspection and maintenance QA/QC program are designed to improve the collection and monitoring of field inspection data and work completed information. The Company anticipates incremental annual expenses of these initiatives to be $2.45 million in CY11, $2.9 million on CY12 and $2.9 million in CY13. Exhibit __ (IOP-8) provides a calculation of these estimated costs.

B. Transmission Tower Painting and Comprehensive Aerial Inspection Programs

Q. The Company's proposed rate year expenses reflect approximately $4.6 million in additional costs associated with transmission tower

painting and a comprehensive aerial patrol program. Could you elaborate?

A. Yes, the Company plans to spend an incremental $2.6 million annually for the transmission tower painting program and $2.0 million annually for a comprehensive aerial and footer inspection program as compared to the historic test year.

Q. Can you describe the transmission tower painting program?

A. The Company has adopted a tower painting initiative following the implementation of the NY Steel Towers Mitigation Strategy described previously. This initiative, the Tower Painting and Structure Replacement Strategy, is aimed in part at extending the life of mature steel transmission towers in Visual Category 4. In addition, this strategy seeks to delay or prevent Visual Category 1, 2, and 3 structures from degrading into the Visual Category 4 condition or worse. The Company has approximately 20,000 steel structures operating at 115kV or higher in New York, with an average age of 65 years. Approximately 1,350 of the 17,500 steel towers inspected to date are in Visual Category 4. The painting program maintains the integrity of these existing steel towers, promoting longer service lives, reliability and safety in a very cost-effective manner. Presently, the tower painting program is operating on a 15-year cycle (after this cycle, it will be modified to a 20-year cycle). A 15-20 year painting cycle is consistent with cycles used by other utilities in the northeast.

Q. How was the $2.6 million adjustment to the historic test year expense determined?

A. Due to vendor safety performance issues, the tower painting program was suspended from August 2008 to June 2009, and again suspended in August 2009. As a result, the total annual estimated costs of this on-going program are not reflected in the historic test year expense. The $2.6 million adjustment to the rate year expense is intended to capture the costs of the work, which is anticipated to restart in June 2010. The $2.6 million adjustment is based on historical information on tower painting costs. The Company's annual tower painting budget is approximately $3.4 million, based on the historical average cost to paint a tower and the targeted number of towers to be painted annually. However, due to the program suspension, tower painting expenses for the historic test year were only about $800,000. The $2.6 million adjustment reflects the difference between the historic test year spend and our estimate of what the program will cost during the rate year. Exhibit __ (IOP-9), Schedule 1, illustrates how the $2.6 million adjustment was determined.

Q. Please describe the comprehensive aerial patrol and footer inspection programs.

A. The Company is undertaking a comprehensive aerial helicopter patrol program with an estimated incremental cost of $1.4 million per year over a three year period, and a footer inspection program plus additional inspection programs to further investigate structural issues identified by the aerial patrol at an estimated cost of $600,000 per year for a three year period.

Q. What are the expected benefits of the comprehensive helicopter patrol?

A. This program utilizes helicopters with high resolution cameras that will hover over structures to identify defects such as cracked insulators, defective hardware and structural steel members, and deteriorated foundations. The patrol will take place on the 20 worst performing circuits over a three year period to develop a comprehensive maintenance schedule to correct the identified issues prior to failure in order to improve the reliability of the identified circuits.

Q. What are the expected benefits of the footer inspection program and other miscellaneous inspection work identified by the aerial patrol?

A. As discussed previously, the aerial patrol will identify deficiencies in the overall structure and the foundations. It is anticipated that additional on-site below grade footer inspections will be required as a follow-up to determine the full extent of the repairs required or if replacement is warranted. As with the aerial patrol, this effort will identify issues prior to failure in order to improve the reliability of the identified circuits.

Q. How were the estimated costs of the aerial patrol and footer inspection determined?

A. As shown in Exhibit __ (IOP-9), Schedule 2, the estimated costs for the comprehensive aerial patrol and footer inspections are based on actual vendor costs in the test year which are then multiplied by the expected level of work.

C. <u>Vegetation Management</u>

Q. Please explain the Company's $5.0 million adjustment to historic test year expenses related to vegetation management activities.

A. The adjustment for vegetation management activities includes $2.1 million of anticipated new costs for work on the transmission system, and approximately $2.9 million on the distribution system.

The Company strives to be a leader in appropriate vegetation management practices to maintain and improve reliability and follow all regulatory requirements. Pursuant to PSC rules, the Company files a Transmission Right-of-Way Management Program (Part 84 Plan), which is subject to approval by PSC. The Company's most recently approved Part 84 Plan is dated November 2003, and incorporates proven vegetation management practices in order to facilitate uniform and consistent management of our transmission system. Additionally, in June 2005, the PSC issued an Order requiring enhanced transmission right-of-way management practices by electric utilities (Case No. 04-E-0822 – In the Matter of Staff's Investigation into New York State's Electric Utility Transmission Right-of-Way Management Practices). Niagara Mohawk has been complying with the PSC orders, and enhancing our vegetation management program to further improve reliability.

In an effort to improve reliability, the Company plans to widen many 115 kV rights-of-way (ROWs). Trees located outside of transmission ROWs that fail and fall into the lines are the source of most tree-caused service interruptions. As the growth of trees outside the existing ROW (i.e., the "utility forest") increase, so does the potential for the trees to grow into the electric lines, or upon failure, interrupt electric service. The Company's

115kV system has the greatest risk exposure to tree-related outages on our transmission system, and intervention in the form of enhanced ROW widening efforts provides a cost-effective means of reducing future reliability effects from off-ROW trees, and improving safety. Widening activities will be performed in accordance with Transmission Group Procedure No. 25, Right-of-Way Vegetation Management Plan, Level 6 requirements, which are defined as the removal of all trees to a new cleared width, where property rights allow. The projected annual cost of the 115 kV widening program is $1.5 million. Exhibit __ (IOP-10), Schedule 1, illustrates how this amount was determined.

The Company's rate year expense also reflects costs associated with new initiatives aimed at the protection of two rare butterfly species: the Karner Blue Butterfly and the Frosted Elfin. The Karner Blue Butterfly is listed on both the Federal and New York endangered species lists, while the Frosted Elfin is on the New York State list of threatened species. The local principal habitat of these species in the area of the Albany Pine Bush, and previous studies of the Company's vegetation management practices have determined that decades of ROW management is largely responsible for creating habitats favorable to the Karner Blue Butterfly and Frosted Elfin. In order to be able to continue to operate and maintain its electric transmission system in the habitat area of the Karner Blue Butterfly and Frosted Elfin, the Company was required to develop and fund a Habitat Conservation Plan ("HCP") in support of its application to the U.S. Fish & Wildlife Service for an Incidental Take Permit ("ITP") under the Endangered Species Act. Exhibit __ (IOP-10), Schedule 2, is a copy of an April 30, 2009 letter to the U.S. Fish and Wildlife Service describing the Company's HCP and the estimated funding for the HCP. It is anticipated that the ITP will cover the Company's utility activities on affected ROWs and other properties for up to 50 years. The anticipated cost of the program varies over time, but it is projected to have a start-up cost of approximately $200,000 per year during the proposed rate plan period. These costs are not reflected in the historic test year.

In addition, the Company is proposing an upward adjustment to the historic test year cost associated with ROW floor trims. The historic test year costs for ROW floor trim sites are the result of a lower than average number of trim site acres. The number of trim site acres fluctuates annually, but costs are expected to average approximately $935,000 in the proposed rate plan period, an increase of $400,000 over the historic test year amount. Exhibit __ (IOP-10), Schedule 4 provides a calculation of these estimated costs. Trim site costs and acres are reported annually to the Secretary of the Department of Public Service.

Q. Can you please explain the Company's current programs for removing hazard trees?

A. The Company's has two reliability-based programs that involve hazard tree removal: cycle pruning of circuits, and Enhanced Hazard Tree Mitigation ("EHTM"). During routine maintenance cycle pruning, in addition to pruning trees, imminent danger hazard trees immediately next to the lines are identified and removed. Alternatively, the EHTM program targets circuits specifically in need of extensive hazard tree removal work independent of the cycle pruning schedule. The EHTM program is aimed at minimizing the frequency and damaging effects of tree and large limb failures from high-risk trees located along side or above the Company's primary distribution facilities, and therefore focuses on hazard removal to a much greater extent than cycle pruning. The EHTM program uses a risk analysis protocol to prioritize high risk and poor performing areas on a circuit and evaluate them for the potential need for hazard tree work. These identified areas are then extensively inspected for risk trees and large limbs, and those above a pre-determined risk level are scheduled for removal. The EHTM program comes at a higher cost per mile than cycle pruning since more trees are being removed. For this reason, EHTM is only performed on circuits showing poor reliability, specifically in need of intensive hazard tree removal. This program has had favorable results and has shown to improve circuit reliability.

Q. Can you please explain the proposed incremental cycle maintenance hazard tree program changes requested by the Company?

A. The Company's reliability performance indicates we are experiencing continued interruptions due to tree or large limb failure. In an effort to realize reliability benefits similar to those of the EHTM program, without reaching the intensity level and higher cost of the EHTM program, the Company wishes to increase the number of routine maintenance pruning hazard tree removals on the remaining pruning circuits not scheduled for EHTM for a projected cost of $2.9M as shown in Exhibit__ (IOP-10), Schedule 5. Since this enhancement is new, the $2.9 million cost is incremental above historic amounts. The same EHTM tree risk analysis protocol will be applied to these maintenance pruning hazard removals, ensuring that the highest risk trees along a circuit are properly prioritized. This will allow us to reduce the risk of interruptions by tree and large limb fells when compared to historic cycle pruning hazard tree removals providing the potential for greater reliability improvement.

D. <u>Increased O&M Expense Related to Infrastructure Investment</u>

Q. The Revenue Requirements Panel addresses projected increases in O&M expenses of approximately $12.9 million in 2011, $18.6 million in 2012, and $22.8 million in 2013 from historic test year expense levels associated with the Company's proposed infrastructure investment plan in Exhibit __ (RRP-2), Schedule 35. Please explain the basis for these projected expense increases for the rate years?

A. In addition to general O&M cost discussed above, there is a level of O&M required to implement the Company's infrastructure investment plan presented in this case. The Company follows established accounting rules governing how work is classified as O&M, capital, or removal that are based on the Federal Energy Regulatory Commission (FERC) accounting regulations.

The accounting rules provide that O&M accounts shall be charged for labor, materials, overheads and other expenses incurred for certain types of work that include the following activities:

- Direct field supervision of maintenance;

- Inspecting, testing and reporting on conditions of plant specifically to determine the need for repairs, replacements, rearrangements, and changes; and inspecting and testing the adequacy of repairs which have been made;
- Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining the life of plant;
- Rearranging and changing the location of plant not retired;
- Repairing for reuse of materials recovered from plant;
- Testing for, locating and clearing trouble;
- Net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in customer service; and
- Replacing or adding minor items of plant which do not constitute a plant unit.

Virtually all capital projects constructed involve interfacing with existing facilities. Many of these projects involve a combination of complicated reconfigurations of existing facilities and construction of many interface points between new and old facilities. When there are existing facilities of any kind involved, there will be O&M costs.

Q. Could you provide an example of a capital project that would require the incurrence of O&M costs?

A. Yes. Using a tower replacement as an example and following the established guidelines, an example of O&M costs that could be incurred include:

- Maintaining previously constructed access roads or ROW:
  - Repairing roadways, bridges etc.
  - Trimming trees and brush to maintain previous roadway clearance
  - Maintenance work on publicly owned roads and trails when complete
  - Chemical treatment of right-of-way areas
- Performing the work
  - Detaching conductor and shield wire from the old tower, transferring and reattaching it to the new tower
  - Cleaning insulators
  - Repairing grounds
  - Re-sagging, re-tying or re-arranging position or spacing of conductors

Other indirect project costs which are required to perform the capital project yet cannot be attributed to a specific capital asset, will also contribute to O&M charges for a project. These costs are apportioned to capital, cost of removal and O&M based on the overall project estimate and include: engineering, direct field supervision, railroad flagmen, police protection, switching, grounding, wildlife protection, and the installation of swamp mats and hay bales/silt fences.

Q. How did the Company calculate the annual amounts for incremental O&M expense related capital?

A. As mentioned previously, the Company's infrastructure investment plan presented in this case represents an increase from the investment reflected in the historic test year. To calculate the amount of incremental O&M expense the Company would expect to incur to deliver the increased capital plan, the Company took a three-year average (FY 2007 – FY 2009) of the ratio of annual O&M costs to capital costs for electric transmission (segregated into lines and substations, sub-transmission and distribution, and applied the resulting percentages to the planned incremental capital investment in each segment to arrive at an estimated annual adjustment. For example, for transmission lines, the 3-year (FY 2007 – FY 2009) average ratio of total O&M costs to capital costs is 10.26%; for transmission substation: 0.88%; for sub-transmission: 4.27%; and for distribution: 7.89%. These percentages were then applied to the plan incremental capital investment (compared to the test year) in each area. The result is that the Company expects to incur total increased O&M expense associated with the increased capital plan of $12.9 million in CY 2011, $18.6 million in CY 2012, and $22.8 million in CY 2013 (as compared to the historic test year).

Q. Will the Company realize any O&M cost savings as a result of the planned infrastructure investments?

A. Yes, but they will be relatively small. In 2007, the Company forecast that it would achieve $598,485 in O&M savings during 2008 as a result of the incremental expenditures it made on electric system capital projects and related O&M during 2008. After reviewing data from 2008, the Company estimated that it achieved a total of $492,715 in O&M savings for 2008. A similar level of cost savings would be anticipated for FY11 through FY14 under the plan presented in this case.

Q. Given the scope of the investment, why wouldn't the Company anticipate a greater level of O&M savings?

A. O&M cost savings are limited because generally, substantial O&M savings would be produced by capital or capital-related O&M spending only if the expenditures enable the Company to reduce the total number of personnel devoted to maintenance and repair of the electric system. The Company did not reduce the number of personnel performing those tasks during 2009 and it does not expect that going forward the increased capital expenditures on the electric system will enable it to do so.

Even though the Company is spending hundreds of millions of dollars on its transmission and distribution facilities, those expenditures result in the replacement of a small percentage of circuit breakers, conductor miles, steel towers, and other such assets that make up the entire electric system. The replacement of a small proportion of these assets makes no significant difference in the volume of routine maintenance activities such as visual and operational inspections, infrared surveys, and foot patrols. These activities are required whether an asset is new or old, and in the case of relay equipment, station batteries and diesel generators, maintenance intervals are mandated by NPCC standards. For the same reason, while it is assumed that there will be a decrease in the amount of "found-on-inspection" and "follow-up" maintenance activities associated with new equipment, this decrease is relatively small due largely to the vast number of assets on the system. Even though equipment is replaced, the system in aggregate continues to deteriorate and thus requires continual maintenance.

E. <u>Storm Response Costs</u>

Q. How does the Company recover its costs associated with responding to storm events that affect the electric system?

A. The Company currently recovers the costs of responding to storm events in two ways: (1) through base rates for normal storm events; and (2) through a deferral mechanism for major storms. Responding to normal storm events is part of the ordinary cost of business for an electric utility, and the costs of doing so are generally reflected in the utility's base rates. However, utility systems are occasionally also affected by significant weather events that cause substantial damage and result in the incurrence of costs that are out of the ordinary. These costs are also legitimate and necessary costs of providing service to customers. However, because the costs of responding to extraordinary storms vary and cannot be accurately predicted year-to-year, base rate recovery for such costs is generally not provided. Rather, in the Company's case, the costs of responding to extraordinary storms are reflected in a deferral account.

Q. Please describe the Company's major storm deferral mechanism?

A. The Company's existing major storm deferral mechanism was established in the MJP, and further refined pursuant to the March 22, 2007 Stipulation of the Parties in that case, which the Commission approved by order dated July 19, 2007. Under the storm deferral mechanism, the Company is authorized to include in its deferral account those incremental costs above $2 million associated with any individual major storm in a calendar year, subject to a $6 million annual deductible for incremental major storm costs. Under the Merger Joint Proposal, every two years (coincident with the Company's CTC reset filing) the Company is required to seek recovery, or provide a refund, of the cumulative amount by which the deferral account exceeds $100 million. The Company made its most recent CTC reset and deferral account recovery filing on August 3, 2009 for the actual deferrals as of June 30, 2009 and forecasted deferrals through December 31, 2011.

Q. What is considered a "major storm" for deferral purposes?

A. The Commission's regulations (16 NYCRR pt. 97) define "major storm." The Stipulation of the Parties mentioned above further refined a "major storm" for purposes of deferring response costs. For deferral accounting purposes, a major storm is essentially a period of adverse weather which results in electric service interruptions to 10 percent or more of customers in an operating region, or at least one percent of the customers within an operating region being interrupted for over 24 hours.

Q. What level of storm costs has the Company deferred under the deferral mechanism you describe?

A. From April 2005 through August 2009, the Company incurred approximately $152 million—or about $34 million per year— of costs that qualified for deferral under the criteria established under the Merger Joint Proposal and Stipulation of the Parties. This deferral amount includes $78 million for the October 2006 Buffalo storm, and $47 million for the December 2008 ice storm.

Q. Please describe the Company's proposal relating to the recovery of storm costs.

A. The Company proposes establishing a fully reconciling storm fund of $30 million to offset the costs of responding to uncontrollable major storm events. This storm fund amount is approximately 88 percent of the average annual amount of major storm costs that have been eligible for deferral during the same 4.5 year period.

Q. Why is the Company proposing to modify the current mechanism for addressing major storm costs?

A. Currently, if the Company's system is affected by a major adverse weather event, the Company may have to incur tens of millions of dollars in unforeseen costs in a very short time period. These costs are often payments to third-party contractors and suppliers, and can have a significant effect on the Company's cash flow. Although the current deferral mechanism provides an opportunity to recover these costs, such recovery may occur more than 4 years after a storm, depending on the timing of the event.

Establishing a storm fund to which customers contribute over time would provide a source of funds to respond to these significant events, and reduce the potentially significant cash flow impacts which can result from a major storm. In addition to enhancing the availability of funds needed to respond to a major storm, a storm fund is also expected to provide greater matching of cost recovery with cost incurrence.

Q. How would the storm fund operate?

A. The storm fund would work as a pre-funded account. The Company would include an amount in base rates which would be used to fund the storm fund, and major storm costs would be assessed against this account balance. If the balance of the storm fund is brought below zero as of December 31 of any year because of major storm costs, the Company would recover an amount to bring the fund balance to zero through the EDAM described in the Revenue Requirements Panel testimony.

Q. Is the Company proposing to change the types of major storm costs that are eligible for recovery?

A. No. The Company proposes to use the existing criteria that were established for deferral of storm costs.

Q. How did the Company determine the proposed storm fund amount?

A. The proposed storm fund amount is slightly less than the annual average of the Company's deferred major storm costs from April 2005 through August 2009 (i.e., $152 million/4.5 years = $33.78 million/year). The establishment of the storm fund is not intended to insure the availability of all the funds necessary to respond to every major storm, but rather to help meet the substantial short-term cash demands that result when the inevitable major storm event occurs. Exhibit __ (IOP-11) provides a summary of the major storm deferral amounts described above that were used to arrive at the proposed $30 million storm fund amount.

F. Site Investigation and Remediation

Q. What is the Site Investigation and Remediation ("SIR") program?

A. The SIR program refers to those activities undertaken and costs incurred by the Company in connection with the management and remediation of environmentally contaminated sites. Such sites might include former manufactured gas plant sites, other Company operating sites that have become environmentally contaminated, or non-Company sites where the Company faces potential PRP (Potentially Responsible Party) exposure relating to alleged liabilities under Federal or State Superfund law or other law or regulation relating to the control of hazardous waste or substances. The Company's current electric rates include base recovery of $12.75 million per year for SIR costs. This amount represents the 85% electric allocation of the total $15 million SIR costs previously established in rates for both electric and gas operations. To the extent actual electric SIR costs exceed or are less than the annual rate allowance, the difference is deferred for subsequent recovery or return.

Q. What types of costs are incurred under the SIR program?

A. Allowable costs under the SIR program include associated consultant and contractor costs, base labor expense as well as incremental internal labor used for SIR activities, remediation activities aimed at reducing the volume, toxicity or mobility of pre-existing contamination, and incremental external costs, including insurance and legal costs, incurred to seek recovery from third parties or to otherwise seek to mitigate the Company's costs or liability associated with the SIR program. Under the MJP, allowable SIR costs are to be offset by: (1) net gains from the sale or transfer to Non-utility Property of the Company's land and buildings included in rate base, or from the sale of stone, gravel, sand or timber from such land; (2) any net gains recognized from the leasing of such land or from the sale or lease of mining or drilling rights to such land; and (3) net insurance proceeds and net recoveries from third parties.

Q. What have the Company's historic SIR costs been?

A. The Company's current level of SIR recovery in electric rates is $12.75 million. However, the Company's actual total SIR expenses over the period FY 2003 – FY 2009 have been:

FY 2003: $28,675,183

FY 2004: $22,045,153

FY 2005: $29,610,349

FY 2006: $21,680,242

FY 2007: $18,644,941

FY 2008: $14,731,334

FY 2009: $33,663,069

The variability in annual amounts results from the fact that SIR project spending is significantly affected by whether SIR activities are focused on investigation (when spending is lower) or construction (when spending increases).

Q. What is the most recent level of SIR deferrals associated with the Company's electric operations?

A. As of September 30, 2009, the Company had an SIR deferral balance of $82.3 million. Its forecasted deferral balance at December 31, 2010 is $109 million.

Q. Is the Company proposing a change in the amount of SIR recovery in base rates?

A. Yes. The Company is proposing to increase the annual level of SIR recovery in electric base rates from the current level of $12.75 million to $29.75 million. This is based on annual projected total SIR costs of $35 million, with 85% allocated to electric and 15% to gas.

Q. Was SIR expense addressed in the Company's recent gas rate case (Case 08-G-0609)?

A. Yes. In that case, the Commission approved a settlement which included annual gas SIR expense of $4.5 million. This amount was based on a total gas and electric SIR expense of $30 million per year, with 15% of the total expense allocation to gas operations (0.15 x $30 million = $4.5 million).

Q. Why is the Company proposing total SIR expense of $35 million in this case?

A. As described in the gas case, and as indicated by the historic spending above, the Company's actual SIR spending has been far in excess of its actual rate allowance. Future SIR expense is expected to increase still further as more projects move from the investigation stage to construction. In the gas case, the Company noted that the $30 million estimate it proposed was conservative, and additional recent information bears out that characterization. For the first 6 months of FY 2010, the Company's SIR spending has total $22 million. For the 16 month period from September 2009 through December 2010, the Company projects SIR spending at $64.1 million (with the 85% electric share at $54.485 million). To provide for more current cost recovery, therefore, the Company proposes that annual base rate recovery of electric SIR costs be set at $29.75 million (85% of $35 million).

Q. What is driving the increased SIR expense?

A. The projected average annual spend of $35 million is based on recent spending and ongoing/near term construction projects. It is increased to reflect more recent actual data, as well as for inflation. The project schedule for the MGP sites, which comprise the vast majority of the spending, is controlled by the DEC under Orders on Consent. A copy of the most recent schedule is attached as Exhibit __ (IOP-12). The schedule is intended by DEC to set ambitious completion goals and does not account for project delays related to such things as extended regulatory reviews, permitting, third-party property access issues, or other common occurrences. The DEC meets with the Company and other New York utilities to discuss adjustments to the schedule. Spending projections using the DEC schedule would result in even higher proposed recovery levels.

Q. Does the Company propose to continue the SIR deferral mechanism?

A. Yes. For each year of the rate plan, the Company will compare its net actual electric SIR costs with the amount collected in rates and will reflect the difference, positive or negative, in the EDAM, which is discussed in the Revenue Requirements testimony. The increase in base rate recovery requested here is intended to provide for more current cost recovery and a corresponding reduction in the amounts deferred annually.

Q. What is the Company's proposal relative to SIR labor costs?

A. In the gas rate case settlement, the Company agreed to transfer internal labor costs from the gas SIR deferral account to base rates. The Company proposes the same treatment for electric-related SIR expense, and proposes to transfer deferred SIR labor expense into base rates. Currently, four positions are included in base rates, while five positions are accounted for in the SIR deferral account. Consistent with the treatment reflected in the gas settlement, it is proposed that all nine SIR positions be included in base rates.

Q. The Commission's Order Approving Transfer with Modifications, in Case 09-E-0593, issued December 23, 2009, directed the Company to make a number of adjustments to its accounting books and take other steps to address treatment of costs, including among other things, SIR costs, associated with non-utility property. Does the Company's filing address the Commission's directives in that case?

A. Yes. The actions that the Company is taking to address the Commissions order in Case 09-E-0593 are described in the testimony of the Revenue Requirements Panel and in Mr. Sloey's testimony.

G. <u>Service Quality</u>

Q. Please describe the Company's reliability service quality performance associated with electric operations.

A. The Company's electric reliability performance is measured through the Company's Service Quality Program established in accordance with the requirements of the Commission's July 2, 1991 Order in Case 90-E-0119 (the "1991 Order"). In the 1991 Order, electric service standards were adopted for large New York electric utilities, as a means of ensuring that the utilities provided adequate levels of service. The Service Quality Program includes three discrete metrics for electric reliability: SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration Index), and momentary interruptions ("MI").

SAIFI is calculated based on the total number of customers interrupted divided by the number of customers served and is a reflection of the number of times the average customer is without service annually. CAIDI is a measure of the average interruption duration experienced by those customers who have had an outage and is calculated from the total customer minutes interrupted divided by the customers interrupted. MI are momentary operations recorded at the substation breakers.

The Company's current reliability targets for SAIFI of 0.93 and for CAIDI 2.07, are based historic performance between 1986 and 1990. Despite being established in the late 1980s from a legacy paper-based manual reporting system, the historical SAIFI and CAIDI targets form the baseline for present-day measurement of the Company's reported electric reliability performance.

Q. What events are classified as interruptions?

A. Interruptions are outages of at least 5 minutes in duration and include all outages except those related to major storms. For reliability reporting purposes, a weather event is classified a major storm when at least 10 percent of customers are interrupted or one customer experiences a 24 hour interruption within an operating area.

Q. How are interruptions recorded by the Company?

A. The recording of interruptions for the measurement of SAIFI and CAIDI is accomplished utilizing the System Interruption Reporting database (SIR-SQ), a mainframe-based system that records and stores data related to system interruptions. The legacy SIR-SQ system, which was state of the art when implemented, is a manual, paper-based system that has been used to report reliability performance over the last 14 years. The SIR-SQ system stores information recorded on paper tickets that are manually filled out by line crews during their shifts. Information includes time off, estimated number of customers interrupted and time on. Data on SIR-SQ tickets is then manually entered into the SIR-SQ database by an office technician.

Q. How has the Company performed against the Service Quality Reliability based targets?

A. Following a period of worsening performance in the early 2000s, the reliability of the Company's system has shown steady improvement from 2004 through 2008. In addition, preliminary results for 2009 indicate that the Company has again met its SAIFI and CAIDI performance objectives as illustrated in the chart in Exhibit__ (IOP-3). This will mark the second consecutive year that the Company has met both its SAIFI and CAIDI metrics.

Q. What measures has the Company taken to address reliability performance?

A. To meet its reliability objectives, the Company has developed and executed a work plan that involves substantially increased levels of system maintenance and capital investment to stabilize and improve the system. This investment has been a necessary precursor to the achievement of significant improvement in safety and reliability performance and the Company's recent efforts in this regard are already yielding results.

The Company has taken a number of major steps to improve reliability performance, including implementation of the Reliability Enhancement Program ("REP"), initiation of the Overhead Transmission Line Refurbishment Program, and other operational improvements. The REP and Overhead Transmission Line Refurbishment programs combine infrastructure investment projects and maintenance activities designed to enhance the long-term performance and health of network assets through the implementation of a portfolio of asset strategies. In addition to the base level of spending, since 2006, the Company has spent approximately $190 million in capital and approximately $22 million in associated expenses to achieve targeted reliability performance and renewed asset health. The key elements of the REP included a targeted program to enhance the performance of distribution feeders (Feeder Hardening), feeder sectionalizing through the installation of reclosers and fuses, asset replacement, improved inspection and maintenance, and a vegetation management program. The Company has delivered on this program and customers have experienced improved service reliability as a result. The Overhead Transmission Line Refurbishment Program is a long-term program to rebuild over 30 transmission lines that have demonstrated poor performance because of their condition. Lessons learned from implementing the REP and Overhead Transmission Line Refurbishment Program have helped guide the development of the Company's current business plan, and the associated infrastructure investment and operations plans.

From an Operations perspective, the Company has negotiated new job classifications with the IBEW to utilize line trucks operated by one person crews (OPC's) that are positioned throughout the service territory to improve response time to outages. In addition, the Company has renewed the focus of its control center and field personnel to 'switch before fix' whenever possible to restore as many customer as possible in the shortest amount of time. The reduction in the duration of interruptions resulting from these efforts contribute toward improved reliability performance.

Q. How does the weather affect reliability metrics?

A. Service interruptions associated with adverse weather events are a primary factor affecting the Company's reliability performance. As mentioned previously, outages associated with major storms are excluded from the calculation of SAIFI and CAIDI. In some years, the Company experiences a large number of major storms that are excluded, such as in 2008. In other years, the Company's service territory may be affected by a large number of smaller storms that cause many customer interruptions, but are not excluded, thereby contributing to lower reported reliability performance.

Q. Is the Company proposing any changes to the electric operations service quality thresholds for SAIFI and CAIDI?

A. Not in this case. The Company is addressing modifications to its service quality metrics through a separate effort with DPS Staff.

Q. Are there any other changes the Company wishes to make regarding reliability service quality metrics?

A. Yes, the Company is proposing two additional changes. First, the Company is proposing to modify the existing service quality penalty terms by providing an additional incentive for the Company to improve its reliability performance if it becomes subject to the maximum double penalties established under the MJP. That is, the Company proposes that in the event it is subject to the maximum double penalties under the MJP, and that its reliability performance for at least two consecutive years is within the established reliability targets, that the risk of double penalties would be reduced to the standard single penalty for the following year. Thus, when the reliability penalty level for SAIFI or CAIDI is at $8.8 million based on the current penalty doubling provisions of the MJP, the penalty level would be reduced to the pre-doubling level of $4.4 million upon meeting the reliability metrics for two consecutive years. This process would not otherwise affect the doubling provision.

Q. What is the basis for this request?

A. The Company accepted the risk of increased penalties for poor reliability performance in the MJP. However, once the double penalty band is triggered, there is no provision for the return to the standard penalty levels established in the MJP. This proposal establishes a mechanism to return to the standard penalty bands in the event of continued reliable performance, and provides an additional incentive to consistently achieve reliability goals.

Q. What is the second additional request?

A. The Company proposes to eliminate PSC Cause Code 7 for Pre-arranged Outages from the calculation of SAIFI and CAIDI.

Q. What is the basis for this request?

A. The number of planned interruptions has steadily increased as the Company has increased its proactive management of its assets to address system reliability and sustainability issues. Including planned outages in the calculation for SAIFI and CAIDI creates a disincentive for the Company to correct reliability and asset health issues that require a planned outage. The Company works diligently to minimize the number of planned outages through utilization of energized work practices. In addition, the Company attempts to reduce the impact of pre-arranged outages on our customers through timely notification based on internal Company procedures. However, there are certain types of work that absolutely require an outage. These include voltage conversions, as part of feeder upgrades, where individual transformers must be de-energized to change the operating voltage from 4 to 13.2kV.

The second factor is worker safety. Certain work practices have been established in conjunction with the IBEW, to ensure worker safety and comply with internal and external (OSHA) safety requirements for energized work by line mechanics. These cases are typically due to proximity to energized conductors or, in the case of the replacement of defective equipment such as potted porcelain cutouts, to reduce the risk of failure while the equipment is being replaced. Thus, removing PSC Cause Code 7 from the calculation of the Company's performance metrics promotes long-term reliability and modernization of the system in a safer manner.

VIII. Research, Development and Demonstration ("RD&D") Programs

Q. Please describe the Company's RD&D program generally.

A. 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).

Q. Can you provide an example of how a program in the Company's RD&D portfolio might reduce customer costs or lead to improves reliability?

A. Yes. Included in the Company's proposed portfolio of projects is the Wireless EMS (Energy Management System) project, which the Company would undertake jointly with other utilities and vendors. Wireless EMS would enable further penetration of EMS capabilities and improved SCADA (Supervisory Control and Data Acquisition) information throughout expansive electric networks (such as the Company's) at lower cost than using dedicated communications lines would allow. Other examples include vegetation management projects in the RD&D portfolio. These projects would develop models, tools and techniques that would improve reliability by reducing tree-caused outages without increasing costs.

Q. What sort of work in the RD&D portfolio is aimed at addressing climate change and efficiency initiatives?

A. The Company's plan also calls for continued work in the Renewable Integration area. In the past, the Company participated in EPRI studies focused on Renewable Integration, including, for example: Integrating High Penetrations of Variable Utility-Scale Renewable Power Sources into the Electric Power Infrastructure; Enhancing Grid-Connected Photovoltaic Systems with Advanced Interface Devices; Distributed Photovoltaic: Utility Integration Issues and Opportunities. The Company also has an ongoing project at Niagara Falls, in collaboration with NYSERDA, the objective of which is to install and evaluate the performance of a 100-kW, 150-kWh zinc-bromide (ZnBr) flow battery in conjunction with a nominal 30-kW photovoltaic (PV) system installed on a Niagara Falls State Park facility. Of primary interest to the Company is evaluating the opportunity to shift the renewable generation to meet the customer's peak demand.

The Company will start work on Adaptation Strategies for Climate Change. The purpose of this program is to develop climate change adaptation strategies for the electric distribution and transmission infrastructure. Two studies are envisioned; one focusing on network resilience and the other on flooding. The results of these studies will provide the basis for the Company to potentially modify its system design and operational procedures to mitigate the effect of and to adapt to weather trends going forward and ensure the best location placement of new infrastructure and assess the locations of existing infrastructure.

The Company has and will continue to work collaboratively with other utilities, NYSERDA, and DOE, thereby leveraging the Company's investment in RD&D. All of the opportunities for external funding require a commitment of co-funding which is included in the funds requested for this program. The Company has already negotiated a corporate agreement with EPRI, which covers all National Grid's activities. This has the effect of leveraging funds such that it reduces the cost of the EPRI program to the Company's customers in New York.

Q. Is the Company proposing to recover the costs of its RD&D program in this case?

A. Yes. The Company's revenue requirement reflects incremental recovery above the historic test year amounts of $1.26 million in CY 2011, $2.73 million in CY 2012, and $3.08 million in CY 2013 associated with the RD&D program.

Q. Why is the Company proposing cost recovery for RD&D initiatives in this case?

A. The importance of this program is clear. These investments are needed to reduce the size of future larger investments that would be required if we continued down a business as usual path. Additionally, the program will focus on many of the urgent needs as identified in by New York State Energy Plan (NYSEP) over its 10-year planning horizon. Specifically the program supports all five of the NYSEP's policy objectives[7]:

- Assure that New York has reliable energy and transportation systems;
- Support energy and transportation systems that enable the State to significantly reduce greenhouse gas (GHG) emissions, both to do the State's part in responding to the dangers posed by climate change and to position the State to compete in a national and global carbon constrained economy;
- Address affordability concerns of residents and businesses caused by rising energy bills, and improve the State's economic competitiveness;
- Reduce health and environmental risks associated with the production and use of energy across all sectors; and
- Improve the State's energy independence and fuel diversity by developing in-state energy supply resources.

[7] State Energy Planning Board, 2009 State Energy Plan - Volume I; Governor David A. Patterson, State of New York, December 2009.

Further the program supports four of the five strategies identified in the NYSEP to achieve these objectives: (1) produce, deliver and use energy more efficiently; (2) support development of in-state energy supplies; (3) invest in energy and transportation infrastructure; and (4) stimulate innovation in a clean energy economy. As a matter of business practice, the program supports the fifth objective: (5) engage others in achieving the State's policy objectives through collaborative effort.

The NYSEP Plan identified energy efficiency as the priority resource to meet its multiple objectives. It sets a goal of reducing electricity use by 15 percent below 2015 forecasts. The NYSEP energy plan identifies electric system efficiency as a "wedge" in achieving this goal. The NYSEP states, "Improving efficiency in the delivery of electricity from generation facilities to end-users in a cost effective manner by reducing transmission and distribution system losses will also mitigate prices and environmental impacts." The Company will continue to collaborate with stakeholders across the state in this area. In addition, staff supported by this Program will analyze methods to reduce electric system losses including, for example use of amorphous core distribution transformers. Energy storage is another technology that was identified in the NYSEP to improve system efficiency. The Company's RD&D program has invested in energy storage demonstrations in the past and will continue to evaluate this technology.

To support the development of in-state energy supplies, the NYSEP calls for expanding the Renewable Portfolio Standard (RPS) to 30 percent of the State's electricity needs with renewable resources by 2015. Distributed Renewables, including photovoltaics (PV) have a large technical potential to help meet this expanded RPS. PV installed costs dropped 30 percent from 1998 to 2008.[8] The high level of incentives provided in New York contributed to it being the state with the lowest net installed cost for residential PV systems.[9] New York's net metering law will continue to increase the customer interest in PV. The proposed RD&D program would address the impacts of high penetrations of Distributed Renewables and work to address other barriers associated with the interconnection of these resources.

The NYSEP states, "Because New York's electric infrastructure is old, significant capital investments will need to be made in the utilities' electric transmission and distribution systems to meet future electric

[8] US Department of Energy Lawrence Berkeley National Laboratory Report "Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008" Wiser, R., G. Barbose, C. Peterman, and N. Darghouth. LBNL-2674E. October 2009
[9] Ibid

demand and allow them to continue to provide reliable service. Replacement and improvement of existing aging infrastructure are critical, as system failures not only raise safety and reliability concerns but can also lead to increased system congestion and therefore higher emissions and costs." A major focus on the Company's RD&D program will be to accelerate the use of technology and innovation to ensure that these required investments are made in the most cost effective manner to relieve some upward pressure on rates. For example, the Program's portfolio would include a project to test the Communications and Network systems in substations standard IEC 61850. This new international protocol has been developed to enhance substation automation and is expected to result in significant improvements in both cost and performance of electric power systems. However, despite the projected benefits of IEC 61850, it is essentially untested on the Company's system and within the industry. Once proven, the Company would roll out this standard across its operations and reap the savings benefit for its customers.

In addition to the urgent needs that these RD&D investments will address for our customers, this program will also play a role in stimulating innovation in the clean energy economy. The Company will continue to work with local universities, such as Syracuse University, Rensselaer

Polytechnic University, and Clarkson University and entrepreneurs both inside and outside of upstate New York who are interested in creating businesses and jobs in New York. According to recent studies, New York is behind in developing jobs in and for the green economy. A recent Pew Center study found that jobs in the clean energy economy grew at a national rate of 9.1 percent per year, while traditional jobs grew by only 3.7 percent between 1998 and 2007.[10] In contrast to this national trend, New York lost clean energy jobs at a rate of -1.9 percent per year.[11] According to the same Pew Center study, New York is also further behind in attracting venture capital to the state attracting just 1.7 percent of the $12.6 billion invested in clean energy from 2006-2008.[12] Through its "Capstone" program, the Company would sponsor student design projects at Clarkson University, Syracuse University, RPI, Union College, and the University at Buffalo. The investment in these projects provides the region with the necessary engineering talent to participate in the global green economy. The benefit to the Company, in addition to the project work product, is creating student interest in the energy delivery industry. Participation in capstone design projects also allows the Company to attract candidates for future employment.

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[10] Pew Charitable Trusts, "The Clean Energy Economy: Re-powering Jobs, Businesses and Investments Across America," June 2009.
[11] Ibid.
[12] Ibid.

Q. Does the Company provide a description of the projects included in its RD&D program?

A. Yes. Exhibit __ (IOP-13) includes a summary description of the each of the projects included in the Company's RD&D portfolio, along with the estimated annual funding during the proposed rate plan period for each identified project.

IX. Safety and Environmental Performance

Q. Please describe the Company's approach to enhancing safety and environmental performance.

A. The Company believes a focus on operational excellence results in a safer environment for both employees and the general public. To that end, the Company is working to improve environmental compliance, reduce the risk of environmental incidents and comply with legal and regulatory requirements.

For example, to meet environmental objectives, the Company is working with its construction alliance partner, Northeast Power Alliance ("NEPA"), to implement best management practices ("BMPs") in connection with transmission line re-builds in New York State to protect sensitive areas. Work on hundreds of miles of electric transmission line rights-of-way will involve or be close to freshwater wetlands, rivers, streams, other water bodies, forestlands, wildlife habitats and important agricultural, cultural and historical resource areas. Use of environmental BMPs will help assure that critically-needed transmission line reinforcements and refurbishments are accomplished in an environmentally compatible and responsible manner.

Another example of the Company's environmental stewardship is its SF6 (sulfur hexafluoride) gas program. Equipment containing SF6 gas is monitored for leaks and leaks are mitigated as part of the Company's SF6 Mitigation Plan. Through the use of emerging technologies such as a camera using ultraviolet technology, determining SF6 leak locations and making equipment repairs is addressed on a more expedited basis. The Company also joined the U.S. Environmental Protection Agency Voluntary SF6 Reduction Partnership in 2004 and continues to report reductions on a yearly basis to the EPA.

With respect to safety, the Company is implementing a series of initiatives to enhance the safety of employees and the general public. Through formation of Safety Strategy Committees ("SSC"), the Company is focused on increasing union participation and enhancing safety for all employees. This improved involvement approach and continued focus on ERGO power teaching should provide continuous improvements to our safety performance.

The reporting of near-miss incidents and hazardous conditions has also exposed some areas of concern that may have otherwise gone unnoticed. The SSC teams will further evaluate identified trends in order to recommend corrective actions, and teams are being developed now to evaluate ways of eliminating the most significant safety concerns. The Company's safety department also works closely with our contractor alliances and their safety professionals to share best practices and promote a safe work place.

The Company's objective is to create a working culture directed towards achieving zero injuries and zero work-related illnesses—and at this time the results have shown the effectiveness. Our efforts to enhance public safety are equally robust and evidenced by the on-going improvements with our electric system infrastructure and the creation of a new position within the safety organization, Manager, Contractor, Public Safety and Fleet.

X. Reporting Requirements

Q. Please describe the Company's proposal relative to modifying certain reporting requirements.

A. Niagara Mohawk is subject to several periodic reporting requirements. One such requirement established under the Merger Joint Proposal approved in Case 01-M-0075 is the filing of a Load Pocket Study. The Load Pocket Study filing requirement does not appear to serve any useful purpose at this point, and the Company is seeking authorization from the Commission to cease submitting this study in the future.

Q. Please describe the Load Pocket Study requirement.

A. Section 1.2.22 of the MJP provides in part that:

> Niagara Mohawk will provide to DPS Staff, within six months of the Effective Date and every two years thereafter, economic analyses of the costs and benefits (including the expected impacts on customer commodity costs) of potential transmission investments. These studies will include transmission investments which will have the potential to benefit Niagara Mohawk customers, including, but not limited to, analyses of congestion costs, and local "load pockets," that is, those load pockets within

Niagara Mohawk's service territory whose impacts primarily affect Niagara Mohawk customers.

The Company has produced the required load pocket study every two years, and filed it with the Commission. There are several reasons why this requirement should be reexamined, and potentially eliminated.

Q. Why is the Company seeking to be relieved of the requirement to file the Load Pocket Study?

A. First, the development of the Load Pocket Study requires the engagement of numerous Company resources to produce; yet, there is no evidence that the study is useful. The Company has received no comments, questions, or feedback of any kind from the Commission or its staff on any load pocket study report it has submitted since 2003, suggesting to the Company that the study has limited value to the agency.

Likewise, the Company itself does not derive any business value from the load pocket study. No transmission capital projects have been created or implemented as a result of the findings of a load pocket study. Had the load pocket studies not been required and not performed, there would have been no difference in the Company's construction program or operations during the corresponding period.

Further, independent of any load pocket studies developed to satisfy the reporting requirement, the Company also continues to improve its transmission system in ways that mitigate or eliminate "load pockets." For example, the 2009 load pocket study showed that transmission projects planned for the Company's Northeast Region to fulfill reliability requirements and serve load growth could eliminate the load pocket entirely. In Western New York, the Huntley load pocket is caused by a specific double circuit contingency (lines 193 and 194) and a resulting constraint imposed by loading on line 195. For reliability reasons, the Company has an approved project to re-conductor the line, mitigating the load pocket as an additional benefit. Thus, load pocket mitigation is occurring irrespective of any studies done to fulfill the reporting requirement.

Eliminating the Load Pocket Study requirement would avoid what appears to be an unnecessary use of resources, and promote greater efficiency for the benefit of the Company and its customers.

Q. Does this conclude the panel's testimony?

A. Yes, it does.