National Grid

Niagara Mohawk Power Corporation

INVESTIGATION AS TO THE
PROPRIETY OF PROPOSED
ELECTRIC TARIFF CHANGES

Testimony and Exhibits of:

Infrastructure and Operations Panel
Exhibit __ (IOP-14), Schedule 1
(Redacted)

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PUBLIC VERSION
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REPORT ON THE CONDITION OF PHYSICAL ELEMENTS OF TRANSMISSION AND DISTRIBUTION SYSTEMS

CASE 06-M-0878

PREPARED FOR:

THE STATE OF NEW YORK PUBLIC SERVICE COMMISSION

THREE EMPIRE STATE PLAZA

ALBANY, NY 12223

OCTOBER 1, 2009

nationalgrid

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I. EXECUTIVE SUMMARY

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") submits this third annual report on the physical condition of its transmission and distribution ("T&D") facilities in compliance with a requirement imposed by the New York Public Service Commission (PSC) in its September 17, 2007 order in Case 06-M-0878. The order states the following:

> Finally, although the Reliability Enhancement Plan [aggregate T&D Investment] may cover some of the repairs to deteriorated facilities, we will require National Grid to report to us annually, beginning within 60 days of the Abbreviated Order, and on October 1 annually thereafter, on the condition of all physical elements of its system and to submit on those dates a plan and schedule identifying needed remedial actions, monitoring programs, and repairs to the Niagara Mohawk transmission and distribution system.[1]

Additional guidance in preparation of this document is provided by the PSC's August 15, 2008 Order Concerning Transmission and Distribution Capital Investment Plan. The order states that:

> Based on our review of Staff's analysis and the filing related to National Grid's New York State Asset Condition Report and five-year Investment Plan, we shall direct the Company to continue to assess the condition of its assets, particularly with respect to its distribution system. In its next filing, due October 1, 2008, the Company shall provide a more comprehensive report, including a better explanation of the link between its asset condition and its T&D Investment Plan.[2]

As reflected in last year's condition report, the physical elements of National Grid's T&D facilities are generally in sound condition. However, there are strong indicators for continued infrastructure investment. Some elements of the T&D network were installed over half a century ago. While it is not necessarily the case that every transmission or distribution asset should be replaced at the end of its projected service life, the relative age of the Company's T&D facilities increases the risk that one of those elements will fail under conditions of stress. Also, the report will highlight certain equipment that has proven its poor reliability. These are indications that investment is necessary to lessen the risks of reliability events.

This year's asset condition report is comprised of two major sections. Chapter II - System Condition is an addition to this year's report focusing on how the transmission, sub-transmission and distribution systems are planned to address capacity, reliability and

[1] Case 06-M-0878- Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for Keyspan Energy Delivery New York and Keyspan Energy Delivery Long Island, September 15, 2007, pg. 150-151.
[2] Case 06-M-0878 – Order Concerning Transmission and Distribution Capital Investment Plan, August 15, 2008, pg. 9.

regulatory needs. Chapter III - Asset Condition focuses on the physical assets on the network and provides further insights the condition of those assets as they relate to transmission, sub-transmission and distribution. The new information presented in this report are due to the systematic collection and evaluation of assets through various new and expanded programs as National Grid moves from a "fix on fail" methodology to a proactive asset condition based approach. Asset condition based decision-making will reduce the number and amount of risks on the system that could cause reliability issues as compared to waiting for failures.

Issues identified in the System Condition and Asset Condition chapters are integrated as part of the planning process where common assets and locations exist. In these cases, the Company strives to optimize its capital investments by formulating projects to address both system condition and asset condition concerns in a coordinated manner. Through the budgeting process, as projects are developed, projects are scored using a risk scoring system that factors in the potential risk form safety, reliability, efficiency, and environmental responsibility. The ranking and selection of projects is reviewed in challenge sessions and prioritized to achieve and optimized portfolio of projects and an optimal capital budget.

The following provides a summary of this year’s asset condition report and the link between that and the Company’s investment plans.

A. System Condition

This chapter, which is new this year, describes how transmission and distribution system needs arising from causes such as changes in system load (such as growth or new or expanding customers), changes in bulk power transfers (for example, resulting from new generation sources or changes in the economics of generation dispatch), and improvements to system configuration (new lines and substations) are identified and addressed. System needs relating to specific asset categories are discussed in Chapter III.

Transmission System

National Grid’s transmission system in New York State comprises transmission lines and substations operating at 115 kV, 230 kV and 345 kV. As of December, 2008, National Grid had 4,614 miles of 115 kV lines, 369 miles of 230 kV, and 385 miles of 345 kV. These facilities are extensively interconnected with facilities owned by others in New York, surrounding states, and Canada. The transmission facilities owned by National Grid are all in upstate New York, and do not interconnect with or affect the operation of its generation facilities on Long Island in any significant way.

This section provides an overview of how the Company’s transmission system is planned at both a high level by regional entities with National Grid participation, and at a local level by transmission owners such as National Grid. This discussion provides the foundation for a review of the system needs as well as the projects planned to address those needs.

Most of the capital projects that National Grid is currently pursuing to address system (rather than asset health) needs are local in nature. While these projects are, for convenience, grouped by study area, they are not developed completely independently of each other, but rather developed in a manner that arrives at the optimal integrated solution for the entire system. Moreover, whenever feasible and beneficial, the scope of timing of these projects is designed to address both asset health and system planning issues. There is also a very important interface maintained between Transmission Planning and the sub-transmission and distribution planners in the Distribution organization in order to ensure that the optimal solutions are pursued for the entire system for the benefit of our customers.

With respect to the bulk power transmission system, the New York ISO's 2009 Comprehensive Reliability Plan did not identify any reliability needs for the transmission system. This study emphasizes adequate capability on the major transmission interfaces to support the resource adequacy standards, but does not address local transmission reliability needs.

With respect to local transmission reliability needs, this section discusses those needs by geographic area served by National Grid. Transmission planning projects planned for each area are described, and the needs that they are designed to address are noted. Some projects will address multiple needs, and where this is the case, it is noted in this section. The following are some of the most significant issues currently being addressed by National Grid's transmission planning process:

- Vulnerability to transmission line overloading and low voltages in western New York, partially as a result of retirement of the 115 kV generation at Huntley.
- Adequacy of the 115 kV system in the area north of Rotterdam and North Troy in eastern New York, especially with respect to service to the new Global Foundries (AMD) manufacturing plant at Luther Forest and associated area load growth.
- Upgrading of two major 115 kV substations, [redacted], to comply with NPCC requirements for Bulk Power System (BPS) stations. These stations were not previously considered part of the Bulk Power System until NPCC created its A-10 criteria, and it was determined that both stations are BPS under the new criteria.

Sub-transmission and Distribution System

This section of the report focuses on the planning of the sub-transmission and distribution systems, also referred to as the delivery system. National Grid's sub-transmission system comprises of lines and substations operating at above 15kV but below 115kV. The Company's distribution system comprises lines and substations operating at 15kV and below. The goal of sub-transmission and distribution planning is to develop a capital improvement plan that will meet customer expectations as effectively and economically as possible.

The Company takes a very proactive approach to the management of its assets. First, its Inspection and Maintenance program is designed to find and fix issues before they become problems. Also, the inspections provide detailed information about our assets for further analysis of trends. In addition, planning of the sub-transmission and distribution system assesses capacity, reliability and asset replacement issues in the future. The overarching objective of the initiatives is to get ahead of reliability concerns before they become events. In this manner, the Company will develop and maintain an electric delivery system that meets the performance objectives defined by various criteria and service quality metrics. Project proposals are developed to address the issues identified through these assessments. These project proposals then form the basis of the development of our capital investment plan.

The annual capacity planning assessment involves identifying thermal capacity constraints, maintaining adequate delivery voltage, and assessing the capability of the network to respond to contingencies that might occur, and includes 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.

To facilitate the assessment of the entire network, the delivery system is segregated into 41 Planning Study Areas. With respect to these 41 study areas, this section of the report includes a brief overview of issues in each area, a quantification of the capacity issues forecasted, and a list of project proposals to address forecasted concerns. These project proposals will be prioritized and considered for inclusion in future capital investment plans.

B. Asset Condition

As reflected in last year's condition report, the physical elements of National Grid's T&D facilities in New York are in a condition commensurate with their age. Some elements of the T&D network were installed 50 to 70 years ago and certain classes of assets are approaching the end of their useful asset life. While it is not necessarily the case that every transmission or distribution asset should be replaced at the end of its projected service life, the relative age of National Grid's T&D facilities increases the risk that one of those elements will fail under conditions of stress. Thus, while National Grid will not replace T&D assets based solely on age, it indicates the need for further engineering analysis of the condition of physical elements of the T&D system and, in planning, a factor that can help predict the volume of assets that will require replacement.

The Company's future capital investment plans are targeted at improving customer satisfaction through improvements in the reliability of the network both through the correction of known deficiencies and through a reduction in the likelihood of failure of assets approaching their end-of-life. National Grid's Asset Management approach develops long-term strategies to manage risk at an acceptable level. The Asset Management process was described in detail in last year's condition report and is not repeated herein.

Transmission System

This section provides a detailed condition report of the Company's transmission assets in the New York service territory, which are summarized in Table I-1 below.

Table I-1
Transmission Asset Types (115 kV and above)

Main Asset	Inventory
Steel Structures (Towers and Poles)	20,325
Wood Poles	35,703
Phase Conductor	18,687 miles
Cables	51.8 miles
Substations	313
Oil Circuit Breakers	377
SF6 Circuit Breakers	330
Other circuit breakers	1
Transformers	508
Batteries	260
Chargers	349
Surge Arresters	691
Sensing Devices	835
Reactors	9
Disconnects	2,442
Relays	7,966

Overall, the condition of National Grid's bulk power transmission system (345 kV and 230 kV) is commensurate with its age, though there are issues in each asset class that present age and obsolescence concerns. Some specific areas of interest are as follows:

Structures

- 386 steel structures are graded at a level that requires short term asset replacement.
- There are currently 228 reject wood poles that require replacement
- The overhead line refurbishment (SG080) and wood pole management (SG009) strategies will address these issues

Phase Conductors

- Conductor, static wire and splice issues and failures pose potential safety risk, as well as significant reliability impact. The conductor clearance (SG029), and static wire (SG073) strategies address critical issues specific to this area. The overhead line refurbishment strategy (SG080) provides a systematic long-term approach that will address issues related to aging conductors, shield wires and splices.

Substations

- A few transmission substations have significant issues including obsolete design, obsolete equipment, reliability concerns, and other issues. To address these issues, National Grid is developing substation rebuild strategies for sites such as Gardenville, Dunkirk and Rome.

Circuit Breakers

- The upstate New York Transmission system circuit breaker population is mainly (53 percent) made up of older oil circuit breakers and the majority (90 percent) of these are installed at 115kV. The oil circuit breaker population is becoming a maintenance burden and an increasingly aging population puts system reliability and customer service at risk.
- A long-term circuit breaker refurbishment strategy is currently being developed to replace approximately 176 of the highest circuit breakers over the next 10 years.

Transformers

- National Grid has an operational transformer population of 508 units with an average age of 35 years. Nine percent of the transformer fleet is greater than 60 years old with a further 34 percent between 40 and 59 years old.
- The Company is developing a significant asset replacement program to be implemented within the coming decade to address the 190 highest priority transformers.

Protection and Controls

- Many of the in-service relay systems are of the older electro-mechanical type that do not support modern fault recording and analysis, and moreover, a number of relays are no longer supported by the manufacturer, replacement parts are no longer available and knowledge of their operation both internally and externally is nearly nonexistent. National Grid will be conducting a comprehensive assessment of existing protective relaying and substation control systems followed by a two stage forward-looking technical strategy for replacement.

Other asset groups and details of the performance of these assets and any programs developed to address concerns relating to these assets are provided in Chapter III.

Sub-transmission System

This section provides details about the condition of National Grid's sub-transmission assets. Elements of the system include overhead and underground segments each with various types of asset classes. Table I-2 summarizes these assets.

Table I-2
Sub-transmission Asset Types and Inventory

Sub Transmission Main Assets	Inventory
Towers / Poles	64,400
Line Circuit Miles	3,400 miles
Cable Circuit Miles	1,100 miles

With certain exceptions noted in this report, the physical elements of National Grid's sub-transmission infrastructure are sound, although many sub-transmission assets are of an age which exceeds their original design life of between 40 and 60 years. Some areas of interest are:

Overhead Assets

- National Grid has approximately 59,766 poles. Inspections of 14,409 poles this year found 537 in need of attention within a one to three year timeframe.
- The Company conducted an internal review of insulator failures on sub-transmission lines due to several post insulator failures. A project begun last year to replace post insulators on angled structures on the sub-transmission circuits between [redacted] which experienced the most insulator failure problems, has been completed. In addition, as part of specific line refurbishment projects, insulator issues will be addressed on other sub-transmission lines.
- Table III-58 (in Chapter III) contains a list of the sub-transmission lines that have or will have work carried out on them during 2009-2010 in upstate New York (i.e. they been designed, completed, scheduled or are due to be started in calendar years 2009-2010).

Right of Ways

- National Grid has extensive rights of ways relating to the sub-transmission overhead lines. A program to address issues related to vegetation in these rights of ways was initiated in 2007 based on the top lines impacting Customer Minutes Interrupted, which is targeted to finish in 2012

Underground Cables

- There are approximately 1,100 miles of sub-transmission cable. Approximately one-half is more than 47 years old and one-third is more than 60 years old.
- National Grid is continuing to finalize the Cable Replacement Strategy and project scopes to replace poorer condition cables greater than 60 years of age over a 15 year period in the fiscal year starting April 1, 2010. In the interim, cables that have been identified as poor performers continue to be replaced or are included in project scopes for future budget years.
- An initiative is being developed to review available test and inspection techniques in order to improve underground cable condition information. The plan is to investigate

on-line testing techniques in an effort to characterize standard signatures and anomalies related to underground cables.

Other asset groups and details are provided in Chapter III.

Distribution System

This section of the report provides a detailed description of the distribution system asset condition for overhead lines and underground cables. Table I-3 provides a inventory of these assets.

Table I-3
Distribution Line Asset Quantities

Main Asset	Inventory
Poles	1,232,500
Transformers: Pad/Pole/Underground	446,600
Primary Conductor (Circuit Miles)	35,900 miles
Cutouts	260,500
Switchgear	3,100
Capacitor Banks	4,700
Reclosers/Sectionalizers	1,040
Line Regulators	3,400
Primary Underground Cable (Circuit Miles)	6,900 miles
Manholes	16,800
Vaults	1,800

The distribution system is generally in sound condition. National Grid continues to gather data and monitor assets in a proactive manner to ensure that any increasing trends are identified and the system is fit for purpose. Some areas of interest are:

Structures

- Between December 1, 2008 and August 10, 2009, inspections were completed on 188,800 distribution poles, which represent approximately 15 percent of the population. Based on these inspections, 1.9 percent of the inspected poles, approximately 3,600 poles, are candidates for replacement over the next three years, which is in line with results from last year.
- Approximately 50 percent of the pole candidates identified in the 2008 inspections have been replaced, including 100 percent of Level 1 and 86 percent of Level 2 codes.

Overhead and Padmounted Transformers

- Between December 1, 2008 and August 10, 2009 inspections were completed on approximately 57,000 overhead and 9,900 padmounted transformers, which represent approximately 15 percent of the population. Based on these inspections, less than one percent of both the inspected overhead and padmounted transformers are candidates for replacement

Conductors

- Inspections were completed on 4,800 miles of conductor in 2009. The results identified 349 locations requiring repair of assets such as broken strands, damaged stirrups and/or connectors, or instances of insufficient clearance or improper sag. The percentage of codes returned for conductors is nominally equal comparing 2008 data to the partial 2009 data.
- In 2008 approximately 190 circuit miles of new conductor was installed. Thus far in 2009 (through July 2009), more than 80 miles has been installed.

Cutouts

- Between December 1, 2008 and August 10, 2009 inspections were completed on over 34,000 cutouts, which is approximately 15 percent of the population. Based on these inspections, less than one half percent of the inspected cutouts require replacement due to condition within one year of the assessment.
- A strategy exists to replace all potted porcelain cutouts on the system. The cutout program will replace all of the potted porcelain cutouts.

Underground Cables

- There are approximately 6,900 circuit miles of distribution cable, which is 700 more miles than reported last year, due to improved data analysis.
- National Grid is continuing to finalize the Underground Cable Replacement Strategy and developing project scopes to replace cables in poorer condition and greater than 60 years of age over a 15 year period in the fiscal year starting April 1, 2010.

Other asset groups and details are provided in Chapter III.

Sub-Transmission and Distribution Substations

In this section, National Grid describes those substations which contain distribution or sub-transmission assets. National Grid has 441 distribution substations. A summary of the equipment types and populations for key substation assets is provided in Table I-4 below.

Table I-4
Substation Asset Inventory

Main Asset	Inventory
Substations	441
Circuit Breakers	4,106
Power Transformers	816
Batteries/Chargers	208
Surge Arresters	1,090
Sensing Devices	2,237
Voltage Regulators/Reactors	692
Capacitor Banks	58

In some of the substations, the Company is beginning to see age related degradation in the areas of (1) primary equipment and (2) secondary protection and control cabling insulation. Some areas of interest are:

Substation Assessment

- National Grid has initiated a substation condition assessment approach across all New York substations. This includes a regular visit to each station to review the condition of the assets. The result is a report which gives each asset a condition code of 1 through 4, with 1 being acceptable and becoming less acceptable the higher the number, based on manufacturer family, condition, age and other relevant data.

Indoor Substations

- National Grid has 26 [redacted] indoor 23 / 4.16kV indoor substations that were built in the 1920s through the 1940s which are targeted for replacement. As detailed in Chapter III, a number of these rebuilds are currently progressing.

Metal Clad Substations

- Following on from last year's review of metalclad equipment, further work has been performed to provide a better means to assess the condition of metal clad equipment based on electro-acoustic degradation parameters. The initial review using this technique identified a number of locations where minor repairs or refurbishments were recommended. The review also identified another 22 substations (out of a population of approximately 220) that required major repairs or refurbishments.

Power Transformers

- Of the 15 transformers on the "watch list" from 2008, three were retired due to condition, one failed unexpectedly, eight were removed from the list, and three remain. The latest review added 22 units to the list.

Circuit Breakers

- National Grid has 4,106 circuit breakers (4,053 operating and 53 spares) on the distribution system, with an average age of 33 years. Of these, seventeen circuit breakers are scheduled for replacement in FY 2010 as part of a one for one replacement program. In addition to these one for one replacements more breakers will be replaced and/or decommissioned at locations involved in either substation rebuilds or retirements.
- Due to either obsolescence or poor performance, breakers with condition codes 2 or 3 in certain families listed in Chapter III below are targeted for replacement/refurbishment over the next ten years.

Protection and Controls

- Many of the in-service relay systems are of the older electro-mechanical types which do not support modern fault recording and analysis, and moreover, a number of relays are no longer supported by the manufacturer, replacement parts are no longer available and knowledge of their operation both internally and externally is nearly nonexistent. National Grid will be conducting a comprehensive assessment of existing protective relaying and substation control systems followed by a two stage forward-looking technical strategy for replacement.

Remote Terminal Units

- National Grid is currently developing the program which will install remote terminal unit (RTU) wiring, control, and data acquisition capability on the equipment at twelve substations during FY2009 and FY2010.

Other asset groups and details are provided in Chapter III.

C. Organization of the Filing

The remainder of this document is segmented into three chapters.

- Chapter II. System Condition
- Chapter III. Asset Condition
- Chapter IV. Exhibits

II. SYSTEM CONDITION

This chapter describes how transmission and distribution system needs arising from causes such as changes in system load (such as growth or new or expanding customers), changes in bulk power transfers (for example, resulting from new generation sources or changes in the economics of generation dispatch), and improvements to system configuration (new lines and substations) are identified and addressed. System needs relating to specific asset categories are discussed in Chapter III.

A. Transmission System

National Grid's transmission system in New York State comprises transmission lines and substations operating at 115 kV, 230 kV and 345 kV. Facilities operating at 69 kV and below are generally considered sub-transmission or distribution. As of December, 2008, National Grid had 4,614 miles of 115 kV lines, 369 miles of 230 kV lines, and 385 miles of 345 kV lines.

National Grid is one of many transmission owners in New York State and is extensively interconnected with facilities owned by others in New York, surrounding states, and Canada. The transmission facilities owned by National Grid are all in upstate New York, and do not interconnect with or affect the operation of National Grid's generation facilities on Long Island in any significant way.

The remainder of this section provides an overview of how the Transmission system is planned at both a high level by regional entities with National Grid participation, and at a local level by transmission owners such as National Grid. This discussion provides the foundation for a review of the Company's system needs as well as the projects planned to address those needs. For convenience, the discussions of these needs and projects are grouped geographically; however, the planning process fully integrates the solutions and the area studies from which they emerge.

Transmission Planning Processes

National Grid cannot plan its system without extensive interaction and communication with the other transmission owners due to the interconnected nature of the system. The planning and operation of the transmission grid throughout northeastern North America is coordinated by regional transmission operators (RTOs) and independent system operators (ISOs), with the New York ISO (NYISO) fulfilling this role for New York State. Bulk power system needs and plans to address those needs are evaluated and developed through ISO-level processes that ensure review and input from all appropriate stakeholders. For New York State, the NYISO's Comprehensive System Planning Process (CSPP) provides the framework for this type of planning, with active participation of National Grid, the other transmission owners, and other stakeholders.

While the bulk transmission system needs are the focus of the ISO processes, there are also more localized needs that are more appropriately identified and addressed by National Grid and the transmission owners rather than through the statewide studies performed within the NYISO CSPP. Each transmission owner has more detailed information on their local transmission systems than the NYISO, and the transmission owners have the primary responsibility to perform these local area transmission studies. These needs are identified using the same models and data used in the ISO studies, but that information is supplemented with localized load information, distribution system plans, and asset health information not normally requested by the NYISO planning processes. The local area studies focus on issues that deal more with serving local load than with bulk power transfers across the state, although the interactions between the local system and the bulk power systems are examined and considered. The results of the localized studies are shared with the ISO and appropriate stakeholders, and used to adjust the system models used in subsequent studies. National Grid periodically posts its current Local Transmission Plan (LTP) on its OASIS website, and participates in informational presentations coordinated by the NYISO in accordance with FERC Order 890 requirements. System Impacts Studies (SISs) must be submitted for those projects that can significantly affect the reliability of the bulk power system. SISs must be reviewed by the Transmission Planning Advisory Subcommittee (TPAS) and approved by the Operating Committee of the NYISO.

Most of the capital projects that National Grid is currently pursuing to address system (rather than asset health) needs are local in nature. While these projects are, for convenience, grouped by study area, they are not developed completely independently of each other. Subdividing the system into study areas enables those areas to be studied in parallel, and to more efficiently and quickly complete the task of covering the entire system. As the area needs are identified, care is taken to ensure that interactions between system issues in adjacent areas are considered, and that the projects selected for implementation represent the optimal integrated solution.

Integration of asset health and system planning studies

Just as the needs and solutions for areas that affect each other are examined in an integrated way, so, too, are the needs and solutions stemming from asset health issues and system planning issues. As the Asset Strategy department identifies emerging asset health issues, it notifies Transmission Planning of the facilities involved to obtain input on which lines or substations may be involved in system planning issues. Similarly, Transmission Planning reviews system planning needs and potential solutions with Asset Strategy early in the project development stage. These interactions ensure that wherever feasible and beneficial, the scope and timing of the recommended projects optimally address both asset health and system planning issues.

In addition to the interface between the asset condition and system planning functions, there is a very important interface between Transmission Planning and the subtransmission and distribution planners in the Distribution organization. Distribution has the closest contact with customer loads and is most knowledgeable about localized load developments (increases or decreases). The distribution and subtransmission planners determine how best to serve load at the lower (69 kV and below) voltage levels, and work with the transmission planners to ensure that the delivery points on the transmission system are capable of handling the load, and in some cases, where a large customer is involved, to ensure that the appropriate service options are offered. Transmission planners, when system needs are identified, will consult with distribution planners to determine whether solutions at the lower voltage levels might be the best options to address system needs (Capacitor installations to improve system voltages are one example). Transmission Planning also reviews the configuration of any new substations or expansions proposed by Distribution, to ensure that sectionalizing devices such as switches or circuit breakers are incorporated into the design, to help ensure that the combined transmission and distribution system will operate flexibly and reliably. The interactions between the two groups are frequent and important to ensure that the correct solutions are pursued.

Planning criteria, standards and guides

National Grid plans its transmission system to fully comply with all applicable planning criteria, standards and guides. Specifically, testing is done to ensure compliance with the following:

- North American Electric Reliability Council (NERC) standards. These standards apply to the Bulk Electric System (BES) and various TPL (transmission planning), MOD (modeling), and FAC (facilities) standards are applied in transmission planning. (The BES currently is the same as the NPCC Bulk Power System.)

- Northeast Power Coordinating Council (NPCC) criteria. NPCC document A-2, Basic Criteria for Design and Operation Of Interconnected Power Systems, is applied to the NPCC Bulk Power System, as determined through application of NPCC document A-10, Classification of Bulk Power System Elements.

- New York State Reliability Council (NYSRC) Reliability Rules. These rules apply to the New York State Bulk Power System, which generally includes facilities 230 kV and above plus selected facilities at lower voltages.

- National Grid's internal document, TGP28, Transmission Planning Guide. The guidance in this document applies to National Grid's entire transmission system, not just the BPS or BES.

All of these documents focus on system performance under normal (all lines in service) conditions, and under specified contingencies (one element out of service, often referred to as an N-1 condition, and two elements out of service with time to make system adjustments before the second is lost, often referred to as an N-1-1 condition). They establish the framework for the use of models to predict such performance for both the current year of operation and for future years.

Base case models and study time horizons

For its transmission planning studies, National Grid utilizes PSS/E powerflow and transient stability models and Aspen OneLiner short circuit models that are developed in coordination with the NYISO. This ensures that the best available representations for interconnected transmission facilities not owned by National Grid are incorporated in the company's studies. These models contain data on system configuration, impedances, generation sources, and loads. For certain types of congestion analysis and economic studies, the Multi-Area Production Simulation (MAPS) model is used, also with data obtained through the NYISO. As necessary, National Grid makes adjustments to the data obtained from the NYISO to reflect localized load patterns and other details not included in the NYISO representations, prior to beginning each study.

Compliance with NERC standards requires that the company study at least three time periods: near term (the next year), mid-term (five years from when the study is being done) and long-term (ten years from when the study is being done). These periods are also used in more localized planning studies, extending beyond NERC requirements. As appropriate to each study, limited testing of other years may also be done. Longer term studies (greater than 10 years) may also be done in conjunction with the NYISO and other transmission owners; the New York State Transmission Assessment and Reliability Study (STARS) is one such study with a planning horizon beyond ten years.

Need date versus timing of project implementation

National Grid strives to identify system needs far enough in advance to allow for the development and completion of projects to address these needs. To the extent feasible, projects are timed to go into service just prior to the emergence of potential issues such as facility loadings or voltages outside of applicable standards and criteria. However, there are situations where needs are identified that cannot be addressed with ideal timing. For example:

- New generators and large loads often request interconnection with very short lead time, shorter than the system planning horizon, and sometimes sooner than needed system reinforcement projects can be developed and constructed.

- From time to time, the standards and criteria under which the system is planned are revised, and this can create the need for a project earlier than it can be completed.

- System operations may identify situations where a change would facilitate more flexibility and possible improvements to reliability, but no violation of planning standards or criteria are involved. These may be pre-existing needs that are only recently brought forth for consideration, and the projects to address them are prioritized based on factors such as cost and risk.

For these and other reasons, there may sometimes be a mismatch between a project completion (in-service) date, and the ideal implementation date. Where the need date precedes an associated necessary project, interim plans may be developed to manage any risks that may be experienced until the project is completed.

Bulk Power System Needs

The NYISO's 2009 Comprehensive Reliability Plan did not identify any reliability needs for the transmission system. The NYISO's studies focus on the bulk power transmission system, with emphasis on ensuring adequate capability on the major transmission interfaces to support the resource adequacy standards. In concluding that there is no reliability need at that level, the NYISO is not stating that there are no local transmission reliability needs. The localized analyses are beyond the scope of the NYISO studies and are the responsibility of the individual transmission owners.

The NYISO is in the process of implementing, for the first time, its Congestion Assessment and Resource Integration Study (CARIS). This will extend the NYISO analysis beyond reliability and identify possible transmission needs from an economic perspective. National Grid is supporting this work, particularly with respect to identifying options for the heavily congested Leeds-Pleasant Valley corridor. The process will not be completed for some time yet and thus there are no firm projects in National Grid's transmission plans to implement any solutions that may result from the CARIS process. Due to the timing of the NYISO analysis it may be necessary to undertake certain asset condition related projects on this critical Transmission corridor. The towers on these circuits are 3A/3B design and there are known design shortcomings with this design. Ideally the Company will address these performance issues in conjunction with any CARIS projects. However, the need for risk mitigation may preclude this solution (refer to Chapter III – Overhead Lines for details of the condition issues affecting the Leeds-Pleasant Valley corridor).

Major local area concerns

As described in greater detail in the area summaries, the following are some of the most significant issues addressed by National Grid's transmission plans:

- Vulnerability to transmission line overloading and low voltages in western New York, partially as a result of retirement of the 115 kV generation at Huntley.
- Adequacy of the 115 kV system in the area north of Rotterdam and North Troy in eastern New York, especially with respect to service to the new Global Foundries (AMD) manufacturing plant at Luther Forest and associated area load growth.
- Upgrading of two major 115 kV substations, Clay and Porter, to comply with NPCC requirements for Bulk Power System stations. These stations were not previously considered part of the Bulk Power System until NPCC created its A-10 criteria, and it was determined that both stations are BPS under the new criteria.

Relationships between needs and projects

In the section that follows, the key system transmission needs in each geographic area served by National Grid are summarized. Transmission planning projects planned for these areas are described, and the needs that they are designed to address are noted. Some projects help to address multiple needs; where this is the case, it is noted. There is not a one-to-one relationship between needs and projects because all needs in an area are studied in an integrated manner and the Company's transmission planners seek optimal groups of solutions for all of the needs.

Study area map

Exhibit 1 illustrates the approximate geographic areas described in the following area summaries. The boundaries on the map correspond to retail franchise lines, but since National Grid owns and operates lines that cross the franchise areas of other transmission owners, these boundaries do not completely capture all of the company's transmission facilities. This exhibit is intended to help identify the study area locations described, rather than to identify with precision every line incorporated in those studies.

Western New York –Genesee area

The Western New York - Genesee area includes National Grid's 115 kV transmission facilities from Lockport east to Mortimer and Golah. This study area connects to the Frontier study area to the west. National Grid owns no transmission operated at voltages above 115 kV in this area. The Mortimer station is an interconnection point between National Grid and Rochester Gas & Electric.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – For an outage of c[redacted] the voltage in the Golah area is predicted to fall as low as 75 percent of nominal. This outage condition can also be caused by a bus fault at [redacted] This need has been identified at existing load levels.

- Need #2 – For a fault on one of the two bus sections at the [redacted], the voltage in the Batavia area falls to 88 percent. The loading of the [redacted] also increases to 96 percent of its LTE thermal limit. This loading was found to be as high as 107 percent of LTE for various N-1-1 conditions. This need has been identified at existing load levels.

- Need #3 – For a fault on one of the two bus sections at the [redacted] with the failure of the bus tie breaker to operate, the entire [redacted] will experience an outage. For this system condition, the voltage on the lines between [redacted] will fall to about 80 percent, nearly a 20 percent drop from pre-contingency levels. The voltage on the lines between [redacted] will also fall to 90 percent. The loading of the [redacted] will increase to 120 percent of LTE (103 percent STE), the loading of the [redacted] will increase to 137 percent of LTE (127 percent STE), and the [redacted]

[redacted] will load to 157 percent of LTE (119 percent STE). These concerns have been identified at existing load levels.

- Need #4 – For a fault on the [redacted] bus, with a failure of the bus tie breaker to operate, the entire National Grid station would be taken out of service. This would result in the voltage in the [redacted] area (served from [redacted]) falling to 88 percent. This contingency also results in the voltage along the [redacted] circuits falling below 90 percent.

- Need #5 – During a review of [redacted] station, the conductor size of one of the bus sections was found to be significantly smaller than the other section. After reviewing actual system loading, it was found that the bus loading has come very close to its thermal limit.

- Need #6 – For a double circuit tower contingency that results in an outage of the [redacted] circuit and the [redacted] the [redacted] surpasses its LTE rating. For the existing load levels, this loading is just below 100 percent of the circuit's LTE rating, for five year forecasted loads the loading is at 103 percent of the LTE rating. No project to address this overload has been included in the following section as review of potential options is still ongoing.

Solution projects

- Project #1 – To address the low voltage in the [redacted] area for an outage of the [redacted] circuit, a second [redacted] circuit is proposed. The project involves converting a 69 kV line between [redacted] to 115 kV operation. To prevent bus faults at [redacted] from creating issues, it is proposed to reconfigure [redacted] into three bus sections, with two series bus tie breakers between sections two and three, and to split [redacted] into two sections with two series bus tie breakers. This project will address needs #1 and #4 discussed above and has a targeted in-service date of spring 2013.

- Project #2 – To address the low voltage in the [redacted] area for a bus fault at [redacted] a second 27 MVAR capacitor bank at [redacted] will be constructed. The proposed in-service date for this project is spring 2012. It was found that this project does not correct all the area voltage issues for the full 10 year planning horizon. To fully address the concerns, distribution power factor correction is necessary at the [redacted] distribution stations. A total of about 10 MVAR of compensation is proposed at these stations using both 13.2 kV capacitors connected to the station buses and correction on the distribution feeders. The power factor correction is targeted to be in-service in spring 2013.

- Project #3 – To address the low voltage in the [redacted] area for a bus fault at [redacted] distribution power factor correction will be installed at [redacted] A total of about 15 MVAR of compensation is proposed at this station using both 13.2 kV capacitors connected to the station buses and correction on the distribution feeders. The power factor correction is targeted to be in-service in spring 2013. The [redacted]circuits are being refurbished in FY09/10 under the Overhead Line Refurbishment strategy SG080.

- Project #4 – To address the thermal overload on line #107 for the [redacted] bus fault, the limiting equipment on this line will be replaced. This limiting equipment includes 0.03 miles of overhead conductor and a current transformer at [redacted] This project has a targeted in-service date of spring 2012. A condition driven rebuild of [redacted] station is also proposed, refer to Chapter III- Substation Rebuilds for details of the condition and performance issues at [redacted]

- Project #5 – To address the voltage and thermal issues for a [redacted] bus fault with a failure of the bus tie breaker to operate, a second bus tie in series with the existing bus tie at [redacted] will be installed. This project has a targeted in-service date of spring 2013.

- Project #6 – To address the high loading on the [redacted] bus, the bus conductor will be upgraded. This project has a targeted in-service date of spring 2012.

- Note #1 – As part of the asset condition review discussed in Chapter III of this document, a need to address the condition of the [redacted] was found. As part of the process to determine the appropriate method to address the concern, Transmission Planning provided guidance and ultimately concurred with the decision to rebuild this line and increase the conductor size to 795 ACSR. Planning has incorporated this system change into their review of this area, confirming that it will not replace the need for any projects, nor will it create any additional issues. This project has a targeted in-service date of spring 2013.
- Note #2 – As discussed in the introduction to this section, the new line between Mortimer and Golah, the capacitor bank addition at [redacted] the power factor correction around [redacted] and [redacted] and the reconductoring of [redacted]will all work together to provide an overall robust solution for all thermal and voltage issues in the region.

Western New York – Frontier area

The Western New York - Frontier area includes National Grid's 115 kV and 230 kV transmission facilities in and surrounding Buffalo and Niagara Falls. This study area connects to the Genesee study area to the east at Lockport, and the Southwest study area to the south at Gardenville. National Grid has several transmission interconnections with NYSEG, NYPA, and Ontario in this study area.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – For a double circuit tower contingency, which results in an outage to the [redacted], the remaining circuit between the [redacted] will surpass its STE limit. This need has been identified for existing system conditions.

- Need #2 – Due to the closure of the 115 kV connected generation at [redacted] voltage as low as 85 percent is predicted in the [redacted] area for post contingency conditions. Loading over 100 percent of LTE is also predicted on several circuits during contingencies. Concerns with the condition and location of assets at the [redacted] facility have also been noted as part of the asset condition reviews discussed in Chapter III of this document. This need has been identified for existing system conditions.

- Need #3 – During summer peak days, the recorded voltage on the [redacted] bus has been below 94 percent. System studies predict that the 230 kV voltage at [redacted] will fall to 86 percent for N-1 and N-1-1 conditions. For some N-1-1 conditions, the voltage on the 115 kV system is also predicted to fall as low as 82 percent. Some of the severe contingencies at [redacted] involve bus faults or bus faults with breaker failures, both of which can impact a significant number of area circuits. This need has been identified for existing system conditions.

- Need #4 – For an N-1-1 condition involving an outage of [redacted] followed by contingencies that take out one of the other transformers at [redacted] the remaining National Grid transformer could load as high as 150 percent of its LTE rating (110 percent STE). This need has been identified for existing system conditions.

- Need #5 – For various N-1 outages in the [redacted] region (including outages of [redacted] bus faults), [redacted] will load as high as 116 percent of its LTE rating. This need has been identified for existing system conditions.

- Need #6 – For N-1 outage conditions, the circuit between [redacted] and the future [redacted] Station, referred to as #178, will surpass 120 percent of its LTE rating. Other circuits between [redacted] and [redacted] also showed loading over their LTE limits for various N-1-1 contingencies. This need will be present beginning immediately when the [redacted] substation is completed.

- Need #7 – For N-1 conditions near the end of the 10 year planning horizon, the loading of the circuits between [redacted] surpass their LTE rating. These overloads were also noted for N-1-1 conditions for 5 year forecasted loads.

Solution projects

- Project #1 – To address the overload between [redacted] is planned to be reconductored. This project has a targeted in-service date of spring 2013.

- Project #2 – Due to the voltage issues around [redacted] caused by the generation retirement and the equipment concerns at [redacted] a new 115 kV switchyard at [redacted] is proposed, which will allow the retirement of the [redacted] 115 kV switchyard. This new station includes all 115 kV lines that terminate at [redacted] plus [redacted] are looped in and out creating six new lines. The station will also include two 60 MVAR capacitor banks. This project has a targeted in-service date of spring 2011.

- Project #3 – The construction of [redacted] Station does not correct all issues caused by the retirement of the [redacted] generation and will create some additional overload concerns. Specifically the [redacted] surpass 100 percent of their STE rating for an outage of the parallel line. To correct these remaining concerns, the [redacted] tie will be changed from normally open to normally closed. Closure of the bus tie will require replacement of eleven 115 kV circuit breakers at [redacted] due to increases in available fault current. This project has a targeted in-service date of spring 2011.

- Project #4 – Originally stand-alone projects were proposed to address the low [redacted] area voltages and the [redacted] transformer overloads. These projects were the addition of capacitor banks on the [redacted] 115 kV bus sections and the addition of a second 230 kV bus tie between the National Grid and NYSEG buses at [redacted] As part of the asset condition review discussed in Chapter III.D (Substations) of this document, a need to address the condition of the [redacted] 230/115 kV transformers was found. A need was also identified to address the condition of equipment associated with the 115 kV station at [redacted] (Chapter III-Substation Rebuilds for further details of the condition and performance issues at [redacted] To address all system needs, a comprehensive plan to reconfigure [redacted] was devised. The complete plan involves the replacement of the two 125 MVA transformers with 333 MVA units and a complete rebuild of the [redacted] 115 kV station to a full breaker and a half configuration, including the addition of two 115 kV capacitor banks at the new station. In addition to supporting the voltage and correcting overloads, this plan eliminates serious bus contingencies at [redacted] and replaces thermally limiting terminal equipment on several 115 kV circuits. This project has a targeted in-service date of spring 2014.

- Project #5 – To address the loading of the [redacted], replacement of 0.3 miles of conductor is proposed. This project has a targeted in-service date of spring 2012.

- Project #6 – To address the various N-1 and N-1-1 overloads on the 115 kV circuits between [redacted], reconductoring of the [redacted] is proposed. In addition to the reconductoring, a new 115 kV circuit is proposed to connect directly between [redacted]. These projects will also help improve the voltage in the [redacted] area. This project has a targeted in-service date of spring 2013.

- Note #1 – As part of the asset condition review discussed in Chapter III of this document, a need to address the condition of the [redacted] 230/115 kV transformers was found. As part of the process to determine the appropriate method to address the concern, Transmission Planning provided guidance and ultimately concurred with the decision to replace the existing 125 MVA units with new 125 MVA units (rather than larger, 333 MVA units). Planning has incorporated this system change into their review of this area, confirming that it will not replace the need for any existing projects, nor will it create any additional issues. This project has an in-service date of spring 2012.
- Note #2 – As discussed in the introduction to this section, the new lines, new transformers, new stations and new capacitor banks will all work together to provide a robust overall solution for all thermal and voltage issues in the region.

Western New York – Southwest area

The Southwest area includes National Grid's 230 kV and 115 kV facilities in southwestern New York, and a portion of the 345 kV line from [redacted] This area borders on Pennsylvania to the south and west and connects to the Frontier region to the north at Gardenville. There are several interconnections with Pennsylvania, NYSEG and RG&E in this study area.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – For system conditions with all lines in service and no generation at [redacted] the voltage in the [redacted] area is below 90 percent. This need has been identified at existing load levels.

- Need #2 – As need #1 is for the system with all lines in service, additional voltage issues would be present for N-1 conditions. The proposed system upgrade to address the area need will not address all N-1 and N-1-1 conditions, as an outage of the new system element will put the system back to today's configuration. Thus, more than one project will likely be required to address N-0, N-1 and possibly N-1-1 voltage issues around [redacted].

- Need #3 – For a fault on one of the two bus sections at [redacted] the voltage at the stations served from the lines between [redacted] and [redacted] will drop over 10 percent. This need has been identified at existing load levels. For 10 year forecasted loads, the voltage also dropped below 90 percent.

- Need #4 – For a fault on one of the two bus sections at [redacted] with a failure of the bus tie breaker to operate, the entire 115 kV bus will be taken out. This will result in voltages around 75 percent at the stations served from the lines between [redacted] and [redacted] This need has been identified at existing load levels.

Solution projects

- Project #1 – To address the pre-contingency and many of the post-contingency voltage issues around [redacted] a 345/115 kV station is proposed. This station will provide a connection from the [redacted] 345 kV line to the [redacted] circuits. This project will also include a 25 MVAR capacitor bank on the 115 kV side of the station to support the system during contingency conditions. This project has a targeted in-service date of spring 2012. The [redacted] ircuits are planned for refurbishment under the Company's Overhead Line Refurbishment strategy SG080 to address condition issues on these circuits.

- Project #2 – To address N-1 and N-1-1 voltage issues around [redacted] especially conditions with the new 345/115 kV transformer out of service, a 15 MVAR capacitor bank is planned to be added at [redacted] Station. This capacitor bank, in conjunction with the other projects in the area, will allow the normally open connection between the NYSEG system and the National Grid system at [redacted] to be operated normally closed. Closure of this tie will provide additional voltage support for the area. The addition of the capacitor bank has a targeted in-service date of spring 2010. The closure of the tie to NYSEG has a targeted in-service date to coincide with the completion of the 345/115 kV station in the spring of 2012.

- Project #3 – The closure of the tie at [redacted] will result in the circuit reaching 101 percent of its thermal limit for high Dysinger East transfer levels. To correct this overload, replacement of limiting connections on this line at [redacted] is required. This project has a targeted in-service date to coincide with the change to the operation of the tie in the spring of 2012.

- Project #4 – To address N-1 and N-1-1 voltage issues around [redacted], especially conditions with the new 345/115 kV transformer out of service, a second 27 MVAR capacitor bank at [redacted] is planned. This project has a targeted in-service date of spring 2012.

- Project #5 – To address N-1 and N-1-1 voltage issues around [redacted] especially conditions with the new 345/115 kV transformer out of service, the existing 115 kV circuit between [redacted] and [redacted] is planned to be reconductored. This upgrade will ensure that the line is in service for nearly all hours, as compared to the condition today, where it is out of service most hours due to predicted post contingency overloads. This project has a targeted in-service date of spring 2012.

- Project #6 – To prevent the over 10 percent change in the voltage around [redacted] for [redacted], power factor correction is planned. A total of about 25 MVAR of correction will be added to the [redacted] distribution stations using both 13.2 kV capacitors connected to the station buses and correction on the distribution feeders. This project has a targeted in-service date of spring 2014.

- Project #7 – To address the low voltage during the bus fault with a breaker failure at [redacted] a second bus tie in series with the existing bus tie will be added. This project has a targeted in-service date of spring 2014.

- Note #1 – For a double circuit tower contingency that takes out both 230 kV circuits between [redacted] and [redacted] the generation at [redacted] and the power flow on the 230 kV line into NY from Pennsylvania will create overloads on the [redacted]nd #[redacted] 115 kV lines heading from [redacted] to [redacted] During real time system operation, the predicted post contingency loading on #[redacted] and #[redacted] has been over the STE rating of the circuits, resulting in the need to restrict generation. Normally this issue is dealt with using generation restriction at Dunkirk and no system upgrades would be proposed. As part of the asset condition review discussed in Chapter III of this document, a need to address the condition of the #[redacted] and #[redacted] circuits was found. As part of the process to determine the appropriate method to address the condition concern, Transmission Planning provided guidance and considered the impact on the system various plans would have. As part of that review, a decision was made to reconductor the circuits with 795 ACSR, correcting most of the area constraints. Planning has incorporated this system change into their review of this area, confirming that it will not replace the need for any existing projects, nor will it create any additional issues. This project has a targeted in-service date of spring 2013.

- Note #2 – As part of the asset condition review discussed in Chapter III of this document, a need to address the condition of a portion of the [redacted] circuits was found. As part of the process to determine the appropriate method to address the concern, Transmission Planning provided guidance and ultimately concurred with the decision to rebuild this line and increase the conductor size to 795 ACSR. Planning has incorporated this system change into their review of this area, confirming that it will not replace the need for any projects, nor will it create any additional issues. This project has a targeted in-service date of fall 2011.

- Note #3 – As discussed in the introduction to this section, the new 345/115 kV station, the reconductored lines, the capacitor banks and the closure of the tie to NYSEG will all work together to provide a robust overall solution for all thermal and voltage issues in the region.

Central New York – Syracuse/Oswego/Cortland area

The Central New York – Syracuse/Oswego/Cortland area includes National Grid's 345 kV and 115 kV transmission facilities in central New York, bounded electrically at the Elbridge, Lighthouse Hill, Oneida, and Tuller Hill 115 kV substations. To the west and south of this study area National Grid has interconnections with NYSEG and RG&E at 345 kV and 115 kV, and NYPA's 345 kV lines connect to National Grid's facilities at Clay and Scriba. This study area includes the numerous large generating stations in the Oswego area.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – There are two 345-115 kV autotransformers at the [redacted] substation but only one supplies the 115 kV system. The other is a spare, to be used in the event of a failure of any of the 345-115 kV autotransformers. If the bank that normally carries load were to fail, or must be taken out of service for maintenance, the switching process that must be followed to bring the spare into service is complex and time consuming.

- Need #2 – Two 345 kV breakers at [redacted] and eight 345 kV breakers at [redacted] may be required to interrupt fault currents in excess of their capabilities, as a result of increasing fault current levels in the area.

- Need #3 – NPCC's A-10 criteria for identifying which stations are to be classified as Bulk Power System (BPS) stations has been applied, and it has been determined that the [redacted] 115 kV station is now part of the BPS. This mean that it must be brought into conformance with NPCC's requirements for BPS stations, which include redundant protection systems and breakers with dual trip coils. The existing station does not meet these requirements.

- Need #4 – Under contingency conditions (stuck breaker events that take [redacted] #[redacted] out of service), the [redacted]15kV line will exceed its emergency ratings. This need exists for the 2018 time frame.

- Need #5 – Under contingency conditions (stuck breaker events that take [redacted] out of service), the [redacted]115 kV line will exceed its emergency ratings. This need exists for the 2018 time frame.

Solution projects

- Project #1 – To address Need #1, an additional 345 kV breaker will be installed at [redacted]

- Project #2 – Need #2 will be addressed by replacing the breakers of concern with new breakers with higher interrupting capability.

- Project #3 – To address Need #3, the [redacted] 115 kV station will be upgraded to bring it into compliance with the NPCC BPS requirements, including protection system changes and new circuit breakers.

- Project #4 – The [redacted] 115kV line will be reconductored to address Need #4.

- Project #5 – The [redacted]115 kV line will be reconductored to address Need #5. This reconductoring will be completed in conjunction with strategy SG018 to address steel tower condition issues that were identified by Mott Macdonald in 2005/06 – refer to Table III-12.

Central New York – Utica/Rome area

The Central New York – Utica/Rome area includes National Grid's 345 kV , 230 kV and 115 kV transmission facilities in central New York bounded electrically by the Oneida, Boonville, and Inghams 115 kV substations. To the west this study area adjoins the Syracuse/Oswego/Cortland study area, to the north it adjoins the Northern study area, and to the east it adjoins the Capital and Hudson Valley study area. To the south the National Grid system interconnects with the NYSEG system, and NYPA's 765 kV and 345 kV facilities interconnect with National Grid through the Marcy and Edic substations.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – Under contingency conditions, including the loss of Oneida – Porter line #7, the O[redacted]115 kV line will exceed its emergency ratings. This need exists in the 2018 time frame.

- Need #2 – NPCC's A-10 criteria for identifying which stations are to be classified as Bulk Power System (BPS) stations has been applied, and it has been determined that the [redacted] 115 kV station is now BPS. This mean that it must be brought into conformance with NPCC's requirements for BPS stations, which include redundant protection systems and breakers with dual trip coils. The existing station does not meet these requirements. The deadline for having a project underway to bring this station into compliance with NPCC's criteria is December 2012.

- Need #3 – NPCC's A-10 criteria for identifying which stations are to be classified as Bulk Power System (BPS) stations has been applied, and it has been determined that the [redacted] 230 kV station is BPS. As it was already classified as BPS prior to this study, it was grandfathered out of the changes until such time as significant work to the station was otherwise required. Since breakers on the 230 kV portion of the station were identified as needing upgrades, it must be brought into conformance with NPCC's requirements for BPS stations, which include redundant protection systems and breakers with dual trip coils. The existing station does not meet these requirements. This requirement is not constrained by the same deadlines as the 115 kV portion, as the grandfathering clause is in effect until breaker work begins at the station.

Solution projects

- Project #1 – The [redacted] 115 kV line will be reconductored to address Need #1.

- Project #2 – To address Need #2, the [redacted] 115 kV station will be upgraded to bring it into compliance with the NPCC BPS requirements, including protection system changes and new circuit breakers. The nine 115kV breakers at [redacted] are also candidates for replacement due to their condition – see Table III-35.

- Project #3 – To address Need #3, the [redacted] 230 kV station will be upgraded to bring it into compliance with the NPCC BPS requirements, including protection system changes and new circuit breakers.

Central New York – Northern area

The Central New York – Northern area includes National Grid's 230 kV and 115 kV transmission facilities in north central New York, adjoining the Syracuse/Oswego/Cortland study area to the southwest at the 115 kV Lighthouse Hill substation, and the Utica/Rome study area to the south at the 115 kV Boonville substation. There are interconnections with Quebec, NYPA and NYSEG in this study area.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – Three 115 kV circuit breakers at the [redacted] substation may be required to interrupt fault currents in excess of their capabilities, as a result of increasing fault current levels in the area. This need exists today and is the result of increases in short circuit current levels that have occurred over time.

- Need #2 – Loss of the 115-15 kV transformer or the thyristor-controlled reactor for the [redacted] would result in a lengthy outage, potentially making the area vulnerable to low voltages when the [redacted] line is out of service. There is a concern regarding restoration time in the event of a failure, which exists under current system conditions.

- Need #3 – Failure of the 115-13.2 kV transformer at [redacted] would result in a lengthy outage under the current system conditions because the station is not designed to accommodate a mobile transformer.

- Need #4 – Manual switching is required under existing system conditions at the [redacted] substation during transmission line outages of the [redacted] 115 kV line, resulting in long interruptions to customers.

Solution projects

- Project #1 – Need #1 will be addressed by replacing the breakers of concern with new breakers with higher interrupting capability. The targeted in service date for this project is the fall of 2012. The [redacted] 115kV circuit breakers are also planned for replacement due to condition issues see Table III-35.

- Project #2 – A spare 115-15 kV transformer and thyristor-controlled reactor will be obtained for the [redacted] SVC, to minimize the time it would be out of service should one of these components fail, addressing Need #2. The targeted in service date for this project is the fall of 2012.

- Project #3 – Need #3 will be addressed by installing a tap and switch at the [redacted] substation to enable a mobile transformer to be installed more quickly should a transformer failure occur there. The targeted in service date of this project is the fall of 2012.

- Project #4 – Two new 115kV motor operated disconnect switches and an automated switching scheme will be installed at [redacted] to minimize outage durations for customers when the 115 kV line trips, to address Need #4. The targeted in service date for this project is the fall of 2012.

Eastern New York – Northeast area

The Eastern New York - Northeast area includes National Grid's 115 kV transmission facilities extending north from the Rotterdam and North Troy 115 kV substations, adjoining the Capital and Hudson Valley study area to the south. There are 115 kV interconnections with NYSEG in this area, and with Vermont.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – The [redacted] 115 kV lines are heavily loaded and under contingency conditions can exceed their emergency ratings.

- Need #2 – A major new customer, Global Foundries (AMD) is constructing a new plant east of [redacted] at the new [redacted] site. The existing 115 kV transmission system in the area is not capable of serving the load forecasted for the new plant and the associated load growth projected for the surrounding area. Also, the [redacted] and [redacted] taps may exceed ratings.

- Need #3 – Under contingency conditions, especially with local generation off line, system voltages may drop below acceptable levels. This need will increase as load in the area increases.

- Need #4 – As load grows in the area, partially as a consequence of the Luther Forest development, several sections of existing 115 kV lines may overload under contingency conditions. Of concern are the [redacted] from the new [redacted] to the south, the [redacted] tap from B[redacted], and the [redacted] circuit.

- Need #5 – The area is served from a combination of local generation and supply from the 230-115 kV autotransformers at [redacted] and 345-115 kV autotransformer at [redacted] If two of these transformers are out of service, the remaining banks will exceed their ratings.

Solution projects

- Project #1 – A new 115kV circuit will be added between [redacted] and [redacted] and the [redacted] circuits will be reconductored and reconfigured to prevent the overloading described in Need #1. The system reconfiguration will also be part of the plan to serve the [redacted] and help to address Need #2, though other projects will also be required to completely satisfy that need. During the reconductoring of the [redacted] circuits the Company will also address steel tower condition issues as highlighted in Table III-13.

- Project #2 – To address Need #2, the 115 kV system will be reconfigured to provide two 115 kV sources from the west ([redacted]) and two from the east to the new [redacted] substation. The [redacted] and [redacted] tap from the tap to Ballston will be reconductored.

- Project #3 – A total of 250 Mvar of capacitors will be installed in the Northeast area to support system voltages (Need #3). Some of these capacitors may be installed at the distribution voltage level and some on the 115 kV system. The exact timing and location will be coordinated to address the rate and location of load growth.

- Project #4 – Also to be timed to coordinate with load growth in the area, the #3 circuit to [redacted] will be reconductored.

- Project #5 – A new two-bank, 230-115 kV station will be built at [redacted], north of the [redacted] substation. Five 115 kV circuit breakers at [redacted] will be replaced to avoid exceeding their ratings, these circuit breakers are also candidates for replacement due to their condition – see Chapter III – Table III-35. In addition to strengthening the supply to the 115 kV circuits serving the Northeast area, the new transformers will help to reduce loading on the [redacted] 230-115 kV banks under contingency conditions (Need #5).

- Project #6 – To fully satisfy Need #5, the [redacted] substation will be supplemented by the addition of a fourth 230-115 kV autotransformer at [redacted] See Chapter III Section D for details of the condition and performance issues affecting [redacted] and the proposals to rebuild this station.

Eastern NY – Capital and Hudson Valley area

The Eastern New York – Capital and Hudson Valley area includes National Grid's 345 kV, 230 kV and 115 kV transmission facilities in eastern New York, including Albany and surrounding communities. It extends to the west to the Utica/Rome study area at the Inghams 115 kV station, to the north to the Northeast study area at the Rotterdam and North Troy 115 kV substations, and south toward the Pleasant Valley substation. There are interconnections in this area with NYSEG, NYPA, Central Hudson Gas & Electric, and Con Edison, as well as to Vermont and Massachusetts.

The following section will discuss the needs of the study area followed by a brief summary of projects to address those needs.

Identification of needs in this study area

- Need #1 – The Capital and Hudson Valley area 115 kV system is supplied in part from some local generation, in part from power entering from Central New York through Inghams, and most importantly, by 230-115 kV autotransformers at [redacted] and 345-115 kV autotransformers at [redacted] As load in the area grows, these autotransformers will become susceptible to overloading for situations where more than one of the banks is out of service at the same time. This same issue affects the Northeast area, as previously noted.

Solution projects

- Project #1 – The solutions described in the Northeast area discussion as Projects #5 and #6 also address this need. The addition of a fourth 230-115 kV autotransformer at [redacted] and the new station at [redacted] with two autotransformers will ensure that all of the autotransformers in the area will be within acceptable loading limits even with any two of the banks out of service.

B. Sub-Transmission and Distribution System Condition

The Company's sub-transmission and distribution system in upstate New York serves 1.6 million customers via an integrated transmission, sub-transmission and distribution system. The evolution of the infrastructure over many decades has resulted in the operation and maintenance of a complex network consisting of substations and a combination of overhead and underground lines of various voltages and configurations. This section of the report focuses on the planning of the sub-transmission and distribution systems, also referred to as the delivery system. The goal of sub-transmission and distribution planning is to develop a capital improvement plan that will meet customer expectations as effectively and economically as possible.

Planning of the sub-transmission and distribution system is performed by the Network Asset Planning group via a series of annual assessments and ad hoc reviews addressing capacity, reliability and asset replacement issues. The overarching objectives of these reviews is to provide services requested by our customers and to develop and maintain an electric delivery system that meets the performance objectives defined by various criteria and service quality metrics. Project proposals are developed to address the issues identified through these assessments. These project proposals then form the basis of the development of our prioritized capital investment plan.

Capacity Planning

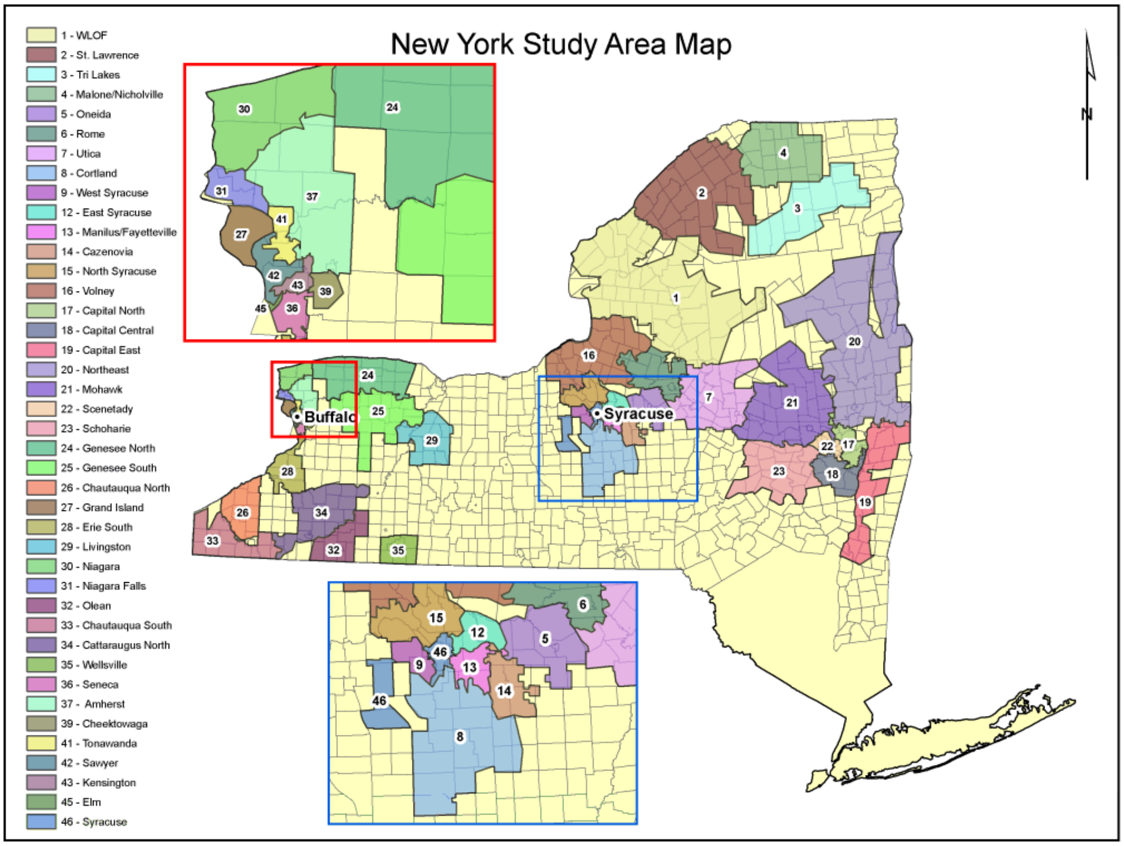
An annual capacity planning assessment is conducted to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur.

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,
- Development of system enhancement project proposals.

To facilitate the assessment of the entire network, the upstate delivery system is segregated into 41 Planning Study Areas. The map below illustrates the geography of these areas.

Figure II-1
New York Study Area Map



Review of Historic Loads

The capacity planning assessment begins with a review of historic loading on each sub-transmission line, substation transformer and distribution feeder. Metered non-coincident peak load information is captured either via the EMS system or through periodic manual meter readings that are stored in the company's FeedPro database. Currently, 45 percent of transformers and 53 percent of feeders have survey metering integrated into the EMS system, while the remaining load information is derived from manual readings taken during periodic inspections.

Peak Load Forecasting

National Grid forecasts Niagara Mohawk's summer and winter peak MW demands using an econometric model that relates monthly peaks to upstate New York employment, households, peak day weather conditions and peak day indicator variables. For the forecast period, two weather scenarios are assumed, normal and extreme. The normal weather scenario assumes peak day temperatures equal to the most recent 30 year average. The extreme weather scenario assumes extreme peak day temperatures that occur only 5 percent of the time, that is, once in 20 years. Capacity planning is performed considering the extreme weather scenario.

Niagara Mohawk's current system peak demand of 6,754 MW was reached on August 2, 2006 and is 7 percent higher than the current winter peak of 6,314 MW achieved on January 15, 2004. Niagara Mohawk's system peak demand grew by an average of 0.7 percent per year over the last ten years, from 1998-2008. This was more than three times faster than energy requirements which increased only 0.2 percent per year over the same period. As a result, load factor, which is defined as average load divided by peak load, declined.

Niagara Mohawk's load factor has declined over the long-term because the upstate New York economy has become more service-sector oriented and the remaining manufacturing base has moved from heavy industry toward smaller, more high-tech oriented businesses. Heavy industrial customers, particularly those that run three shifts, tend to have high load factors. This is because their average use is close to their peak use which is driven more by production schedules than air conditioning. Residential, commercial and small industrial customers, on the other hand, tend to have lower load factors because air conditioning use during hot summer weather can drive their peak use well above their average energy use. Residential and general service (small commercial and industrial) energy sales increased over the last ten years while energy sales to the heavy industrial sectors – large time-of-use (TOU) and New York Power Authority (NYPA) energy sales – declined significantly. This has led to declines in load factor. Peak demand growth was slightly higher over the last five years, averaging 1.0 percent annually, as strong growth in the residential and general service (small commercial and industrial) sectors offset declines in the heavy industrial sectors. For the forecast period, summer peak demand is expected to grow 0.8 percent per year from 2008 to 2018. This is faster than energy requirements which are expected to increase only 0.5 percent per year. Thus, moderate declines in load factor are expected to continue. Most future growth in energy requirements is expected to come from the residential and general service sectors. Winter peak demand, which declined overall since 1998, is expected to see essentially no growth.

The forecasted summer peak demand growth rate of 0.8 percent per year assumes that the summer peak will continue to become more sensitive to weather as the residential and general service sectors continue to outpace heavy industrial. In general, load growth will be driven primarily by increases in use per customer as upstate New York employment and population are expected to be nearly stagnant for the next ten years. In the short-term, through 2009, the housing correction is expected to weigh on both energy requirements and peak demand growth. No growth in peak is expected in 2009.

The New York State Energy Research and Development Authority (NYSERDA) has been implementing demand side management (DSM) and energy efficiency programs in Niagara Mohawk's service territory for over a decade. Niagara Mohawk's rate payers help fund NYSERDA's activities through the System Benefits Charge (SBC) assessed on kWh deliveries. National Grid does not explicitly adjust its load forecasts using estimates of DSM savings from NYSERDA. Actual DSM savings achieved are fully incorporated in the historical load data used to estimate the load forecasting models. For example, the peak demand load forecasting model described above includes a regional employment/population index as an explanatory variable. The estimated coefficient on this variable measures the average change in peak demand resulting from a one unit change in the employment/population index over the historical estimation period. Insofar as NYSERDA's DSM efforts have reduced load, the estimated coefficient on the employment/population index is smaller, indicating that a given increase in employment and population will not increase peak demand as much as it would have in the absence of DSM. Similarly, estimated coefficients on weather variables will also be smaller insofar as DSM has reduced the response of peak demand to weather. The forecast assumes a continuation in DSM savings similar to what NYSERDA has achieved in the past. Expected increases or decreases in DSM activities – by either NYSERDA or National Grid – can be used to adjust the baseline statistical results. Otherwise, making an additional, explicit adjustment to the model results for estimated DSM savings would lead to double counting and bias the forecast downward. This could lead planners to underestimate the system upgrades needed to maintain and improve reliability.

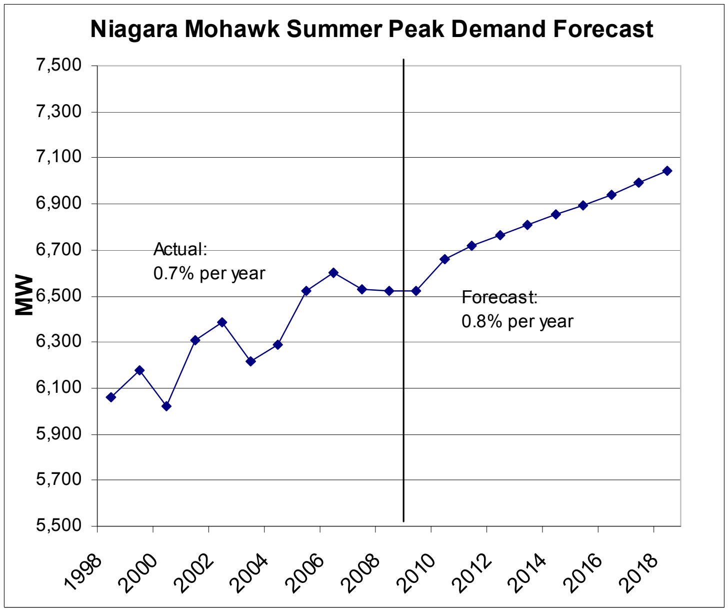
The forecast demand described above does not fully reflect the effects of the recent economic downturn. Also, the forecast does not specifically reflect the potential effects of initiatives such as the establishment of energy efficiency programs by the Company, SmartGrid, expanded distributed generation or targeted demand management. The Company currently is assessing how such factors might affect its forecasts and related system plans, and hopes to incorporate the anticipated effects of such factors in future forecasts.

Peak day weather data were collected from the three major weather stations located within National Grid's Upstate New York service territory. These stations – Albany, Syracuse and Buffalo – are first-order weather stations for which the quality of data is high. Average daily temperatures were collected for the day of the peak, the day prior to the peak and two-days prior to the peak.

Considering both the econometric and weather data, the graphs below depict the forecasted growth in electric distribution demand.[3]

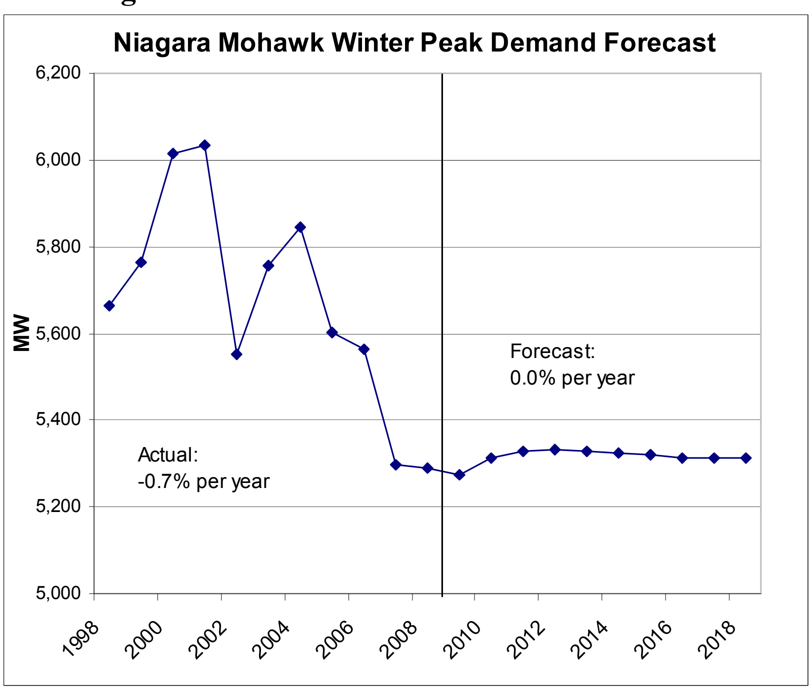
[3] Note that the Company is currently in the process of updating these forecasts.

Figure II-2
Niagara Mohawk Summer Peak Demand Forecast



Preliminary results indicate that the summer 2009 peak was 6,154 MW on August 17. This summer's weather was cooler than average contributing to the decline from the 2008 summer peak demand and the historic peak which occurred in 2006.

Figure II-3
Niagara Mohawk Winter Peak Demand Forecast



Thermal Analysis

Thermal equipment ratings are maintained for each substation transformer and line to be used under various operating conditions. Unique ratings are developed for summer and winter seasons to be applied for both normal system operation and others for use when responding to various system contingencies. The ratings employed generally consider regional ambient temperatures and load cycles which typically results in capabilities above nameplate ratings. The capacity assessment endeavors to identify and address capacity constraints in advance of equipment being loaded beyond applicable ratings.

Contingency Response

As part of the capacity assessment various contingencies are reviewed. The response to contingencies varies significantly depending on whether the system under consideration is of radial or network design. The vast majority of the Company's delivery system is radial design and therefore switching (either manual or automatic) is required to restore service to customers following a contingency that takes the normal source out of service. Network systems are designed such that multiple sources supply customer loads, and upon loss of a single source load is reallocated instantaneously amongst the remaining sources.

Contingency analysis on networked systems reviews the loading on the remaining assets in service to identify and address short term loading concerns. In contrast, contingency analysis on radial systems considers the capabilities of the system to be reconfigured through switching to minimize the extent or duration of customer outages resulting from the loss of normal supply.

To identify locations to enhance the switching flexibility, the capacity assessment identified sub-transmission line and substation transformer contingencies that may result in scenarios in which 240MWHrs or more of load may be at risk if a contingency were to occur during an extreme weather peak load period. Similarly feeder contingencies that may result in more than 16MWHrs of load at risk during peak periods were identified. These areas of load at risk are shared with operations for contingency planning and project proposals are being developed for implementation over a 15 year horizon.

Voltage Analysis

The delivery network is generally designed to provide customers with a service voltage between 123 and 114 volts.

These voltages are maintained via the proper application of transformer tap selection, voltage regulators and both fixed and switched capacitor banks.

Secondary Networks

The Company maintains several local secondary networks in some urban areas. These networks serve a relatively small number of customers. The redundancy built into these systems results in superior reliability performance. Review of these systems is much more complex and must be completed via individual studies. Actual loading on the secondary networks is declining. However periodic studies are warranted to evaluate shifts in load and impacts on the secondary cables. Recently, studies have been completed on the Syracuse Ash and Temple networks, the Buffalo network and the Troy Network. A study of the Albany network is in progress. These network reviews have typically been limited to load flow analysis. Following a failure on the Troy network, the company has developed a process for completing combined load flow and fault studies on secondary networks. The data required to complete the fault studies is extensive and therefore the time to complete future reviews has increased. It is expected that the combined Albany study will be completed by March, 2010.

"General Network" or "Street Grid" refers to the 208Y/120 V network from which customers are supplied directly from the secondary grid. Service sizes are generally limited to three sets of service cables or less. "General Network" transformer vaults are connected to the secondary grid. In concentrated load areas where high reliability is required, networks will be designed and built under double contingency design criteria. For example: for a network with four primary cables, the design shall be such that the network system can withstand the failure of a primary cable with one cable out of service for other reasons. The "network system" includes primary and secondary cables, transformers, network protectors, and ancillary equipment. Other scenarios could involve a combination of any of the following failures: primary cables, network transformers or secondary cables. Secondary cable shall be loaded in such a fashion that limiters shall not blow under normal or emergency loading and cable emergency ratings are not exceeded. Network transformers shall be installed to the extent required so that under single contingency conditions, loads on any transformer shall not exceed 120 percent of nameplate rating. Under double contingency conditions, loads shall not exceed 140 percent of nameplate rating. Under all conditions, loads shall not blow protector fuses.

Spot network vaults are not tied into the general network secondary grid. Spot network vaults are used for all 480/277Y V services and large 208Y/120 V services that cannot be fed directly from the secondary street grid (general network). Spot network 460Y/265 V services exist in some locations and are considered "maintenance only." Spot networks are to be designed for single contingency operation. Loads shall not exceed 140 percent of transformer nameplate rating.

The general networks are designed to maintain the secondary voltages shown in the table below.

Table II-1
General Network (208Y/120 V)

	Upper Limit	Nominal Voltage	Lower Limit
Normal Conditions	126	120	118
Single Contingency	126	120	116
Double Contingency	126	120	112

Annual Capacity Planning Area Summaries

The sections that follow provide a summary of the analysis and recommendations from the most recent capacity planning effort. Individual summaries are provided for each of the 41 study areas and are grouped together for each region; East, Central and West. Each area summary includes a brief overview of issues in the area, a quantification of the capacity issues forecasted, as well as a list of project proposals to address forecasted concerns. These project proposals will be prioritized and considered for inclusion in future capital investment plans.

New York East – Capital Center

Capital Central encompasses the greater Albany area, including a mixture of commercial customers heavily concentrated in the downtown area, and industrial and residential customers spread across downtown to the suburban areas.

The primary distribution system in Capital Central is predominantly 13.2kV with pockets of 4.16kV (area comprised by I-87 and I-90 west of downtown) and 4.8kV (suburban area south of downtown). Most 4kV distribution substations are supplied from the local 34.5kV sub-transmission system, whereas most 13.2kV distribution substations are supplied from the local 115kV transmission system.

The Albany secondary network system is supplied by ten 13.2kV feeders from the [redacted] and [redacted] substations. The Albany secondary network system supplies 34MVA of load from approximately 2786 customers.

[redacted] are the main sources for the local 34.5kV system, which is operated in loop fashion. Besides supplying power to most 4kV distribution substations, the 34.5kV sub-transmission system serves many sub-transmission customers in the downtown area, including the three main hospitals in the city of Albany (Albany Medical Center, Veterans Hospital, and St Peter's Hospital), the State and other government offices (State Plaza, Federal Building, etc), and other commercial customers (Times Union Center, Key Bank, Crowne Plaza Hotel, etc). Five of the 34.5kV sub-transmission circuits supply fourteen customers with spot network service.

Over the years, the growth along the 4.16kV pocket limited by I-87 and I-90 west of downtown has driven the conversion of a few distribution substations and feeders to 13.2kV. However, due to the lack of a transmission system in this area, the size and capacity of these distribution substations are constrained by the limitations of the 34.5kV sub-transmission system. The future extension of the transmission system to this area is believed to be difficult and costly, which can be attributed to the high building and population density of the area. The timing and need for transmission expansion in this area will be collaboratively reviewed by distribution and transmission planning.

[redacted]

Table II-2
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
113	45	88,385	338 MVA

Table II-3
Major Electric Facilities (Substations)

Substations			
Altamont 283	Avenue A 291	Bethlehem 21	Colvin Ave 313
Commerce Ave 434	Delaware Ave 330	Delmar 279	Depot 425
Elsmere 407	Genesee St 260	Juniper 446	Menands 101
New Krumkill 421	Newark St 300	Partridge St 128	Pinebush 371
Quail Hollow 457	Riverside 288	Russell Rd 228	Selkirk 149
Seminole 339	Trinity 164	Unionville 276	Voorheesville 178

Table II-4
Major Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Altamont	Voorheesville	2
Bethlehem	Avenue A	10
Bethlehem	Rensselaer	13
Bethlehem	Selkirk	5
Bethlehem	Voorheesville	1
Colvin Ave	Partridge St	2
Colvin Ave	Seminole	9
Delaware	Bethlehem	14
Delaware	South Mall	37
Delmar	Bethlehem	6
Krumkill	Delmar	9
Menands	Central Ave	8
Menands	Genesee	32
Menands	Liberty St	9
Menands	Riverside	27
Menands	South Mall	36
Newark	Maplewood	6
Norton	Menands	17
Partridge	Avenue A	5
Partridge	Riverside	9
Partridge	Riverside	39
Riverside	Albany Medical Center	16
Riverside	Albany Medical Center	36
Riverside	Dewitt Apts	10
Riverside	South Mall	35
Riverside	South Mall	38
Riverside	Times Union Center	8
Riverside	Times Union Center	14
School	Newark	8

Issues Identified (2009 - 2015)

Significant spot load growth is expected in the city of Albany due to the expansion of Albany Medical Center and St Peter's Hospital, and the construction of the Albany Convention Center. Additional spot load growth is also expected in the town of Bethlehem with the development of the Vista Tech Park and the Selkirk Yards Industrial District.

The following tables provided details on concerns identified in the area over the next six years.

Table II-5
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
5	8	1	2	2	4

Table II-6
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	2	0	0	1	1

Recommended Improvements

In this year's annual plan, field switching has been proposed to address normal loading concerns on distribution feeders out of substations such as [redacted] The implementation of new distribution feeder ties and voltage conversion of 4kV pockets have been proposed to the [redacted], and [redacted] areas to address normal loading concerns on feeders out of [redacted] substations. A project to replace the underground cable getaway for a feeder out of [redacted] has also been proposed as a result of normal loading concerns on that feeder.

Normal thermal loading and contingency concerns on two 34.5kV sub-transmission lines from [redacted] substation to [redacted] substations have been identified for 2011. A solution to this issue is under review and a detailed project proposal will be developed for inclusion in the next Capacity Plan update. During this review, Planning and Operations will collaborate to identify a proper integrated solution to area thermal and asset condition issues; including a comprehensive review of study assumptions (equipment ratings, peak loads, system configuration, etc.).

Table II-7
Project Level Detail of Improvements by Year

Need Year	Summary Level Scope
2010	Add feeder tie with the [redacted] to address contingency concern
2010	Transfer 100A by switching load from feeder [redacted] to feeder [redacted]
2010	Transfer 109A by switching from [redacted] and [redacted] feeders to new 13.2kV [redacted] feeder [redacted]
2010	Transfer 60A by switching load from [redacted] to [redacted]
2010	Transfer load by switching via new feeder tie with [redacted]
2011	Reconductor underground portion of the [redacted] line for approximately 1.8 miles
2011	Transfer 87A (0.6MVA) by switching from [redacted] to [redacted]
2011	Reconductor underground portion of the [redacted] line for approximately 1.1 miles
2011	Transfer 37A by switching from [redacted] to A [redacted]

New York East – Capital East

The Capital East study area is located east of the Hudson River, with the center approximately adjacent to Albany. This area is approximately 20 miles wide at its widest location and extends approximately 63 miles in a north-south direction from Valley Falls in the north to Tivoli in the south. The major roads through the area are US Routes 2, 4, 7, 9 and 23.

The larger load concentrations are in the City of Rensselaer and Troy and in the towns along US Route 9. There is a 345 kV source into the area at [redacted] substation and a 115 kV corridor running in a north-south direction supplying approximately 90 percent of the distribution load directly from the 115 kV system. There is a 34.5 kV system in the area with the major sources from the 115 kV at [redacted] and [redacted] substations and smaller sources from [redacted] and [redacted] There is scattered generation in the area on the 34.5 kV system.

The Troy secondary network system is supplied by two 13.2kV feeders and six 4.16kV feeders from the [redacted]. substation. The Troy secondary network system supplies 14MVA of load from approximately 1583 customers.

Figure II-5
Capital East Area Map

[redacted]

Table II-8
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
81	38	88,200	309 MW

Table II-9
Major Electrical Facilities (Substations)

Substations			
Castleton #36	North Troy #123	Hoosick #314	Sycaway #372
Greenbush #78	Rensselaer #132	Hemstreet #328	Valkin #427
Hudson #87	Hoag #221	Boytonville #333	River Road #444
Lansingburg #93	Seventh Avenue #244	Reynolds #334	Schodack #451
Liberty Street #94	Brunswick #264	Stuyvesant #335	Buckley Corners #454
Menands #101	Tibbits Avenue #292	Corliss Park #338	East Schodack #501
Nassau #113	Blue Stores #303		

Table II-10
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Crescent	School Street	17
Crescent	North Troy	20
Greenbush	Castleton	5
Greenbush	Nassau	6
Greenbush	Snyders Lake	8
Hoosick	Clay Hill	8
Lansingburg	Seventh Avenue	4
Liberty	Tibbits	8
Liberty	Seventh Avenue	5
Nassau	Hudson	9
North Troy	Lansingburg	1
North Troy	Tibbits	2
North Troy	Tibbits	7
North Troy	School St	19
Rensselaer	Greenbush	10
Rensselaer	Greenbush	11
RPI	Tibbits	2

Issues Identified (2009 - 2015)

There are presently no normal thermal issues identified on the 34.5 kV supply lines. Contingency issues on the 34.5 kV supply system are under review and any necessary project proposals will be included in the 2010 annual plan.

Table II-11
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	0	2	0	0

Table II-12
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	2	2	N/A	N/A

Recommended Improvements

There were major additions proposed at [redacted] and [redacted] substations in the 2008 annual plan that are under construction. Those proposed additions, along with a reconductoring project at [redacted] substation, will address all the normal loading issues on the area feeders and transformers.

Table II-13
Project Level Detail of Improvements by Year

Need Year	Summary Level Scope
2009	Install 4 getaways from new switchgear at North Troy substation
2010	Add second transformer bank and (2) new feeders to [redacted] sub to address contingency concerns
2010	Add second transformer bank and (2) new feeders to [redacted] to address contingency concerns.
2010	Installation of a new substation in Alps and the retirement of Hoag and the 34.5kV system

New York East – Capital North

Capital North encompasses the suburban area north of the city of Albany, including a mixture of industrial, commercial, and residential customers scattered along areas such as Colonie, Cohoes, Watervliet, Clifton Park, Halfmoon, Waterford, Niskayuna, and Ballston.

The primary distribution system in Capital North is predominantly 13.2kV with very few pockets of 4.16kV (Newtonville area) and 4.8kV (Town of Ballston). All 4kV distribution substations are supplied from the local 34.5kV sub-transmission system, whereas most 13.2kV distribution substations are supplied from the local 115kV transmission system.

[redacted] and [redacted] substations are the main sources for the 34.5kV sub-transmission system in this area, which is operated in loop fashion. Along with these facilities, a group of hydro and cogeneration power plants located along the Mohawk River (School St, Crescent, Vischer Ferry, Colonie Landfill, etc.) form the backbone of the local 34.5kV sub-transmission system.

Besides supplying power to all 4kV and a few 13.2kV distribution substations, the 34.5kV sub-transmission system also serves several industrial customers in the area, such as Mohawk Paper, Honeywell, Norlite, and Cascade Tissue. Major distribution customers in this area include the Albany International Airport, which is supplied by feeders from [redacted] substations.

Load growth in this area is expected for the perimeter around the Albany International Airport and the Colonie Center Mall.

Figure II-6
Capital North Area Map

[redacted]

Table II-14
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
83	30	80,930	385 MVA

Table II-15
Major Electrical Facilities (Substation)

Substations			
Elnora 442	Everett Rd 420	Fire House 449	Forts Ferry 459
Grooms Rd 345	Inman Rd 370	Johnson Rd 352	Latham 282
Maplewood 307	McKownville 327	Newtonville 305	Oathout Lane 402
Patroon Station 323	Prospect Hill 413	Randall Rd 463	Rifle Range 458
Ruth Rd 381	Sand Creek 452	Shore Rd 281	Swaggertown 364
Wolf Rd 344			

Table II-16
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Central Ave	Patroon	7
Latham	Newtonville	11
Maplewood	Liberty St	2
Maplewood	Norton	5
Maplewood	Latham	9
Maplewood	Liberty St	13
Maplewood	Menands	18
Newtonville	Patroon	16
Patroon	Krumkill	3
Patroon	Colvin Ave	4
Shore	Rosa	5

Issues Identified (2009 - 2015)

Single contingencies on the 34.5kV sub-transmission system in this area could potentially result in unserved load. However, manual switching can be utilized in response to the contingency events and projected exposure does not exceed design guideline limits. Contingency unserved load exposure on the 34.5kV sub-transmission system will be monitored and reviewed closely in future Capacity Plan updates.

Table II-17
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	3	0	0	0	0

Table II-18
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	1

Recommended Improvements

The expansion of [redacted] substation has been proposed to address contingency concerns in that area and to relieve load on adjacent feeders from [redacted] substations. The implementation of new feeder ties at [redacted] substations will address loading concerns in those areas. Normal loading concerns on a feeder out of [redacted] have been identified and the replacement of an underground cable getaway has been proposed. Finally, field switching projects have been proposed to address normal loading concerns on feeders out of [redacted]ubstations.

Table II-19
Project Level Detail of Improvements by Year

Need Year	Summary Level Scope
2010	Add second transformer bank and (2) new feeders to [redacted] to address contingency concerns.
2012	Add feeder tie and transfer 110A from [redacted] [redacted] to [redacted] [redacted] (35A on high side)
2013	Transfer 45A by switching from [redacted]
2015	Transfer 132A by switching load from [redacted] to [redacted]

New York East – Mohawk

The Mohawk study area is defined by the region that includes the city of Amsterdam and the rural areas west of the city. This area is comprised mostly of residential customers and farms with some commercial and industrial customers located in the city of Amsterdam and smaller towns scattered over this region, including Gloversville, Johnstown, Northville, and Canajoharie.

The primary distribution system in the Mohawk study area is predominantly 13.2kV with areas of 4.16kV (Gloversville and Johnstown areas) and 4.8kV (Canajoharie). Most 4kV distribution substations are supplied from the local 23kV and 69kV sub-transmission system, whereas most 13.2kV distribution substations are supplied from the local 115kV transmission system.

[redacted] are the main sources for the local 69kV sub-transmission system, which is operated in loop fashion. The 69kV sub-transmission system supplies power to both 4kV and 13.2kV distribution substations, in addition to a few industrial and commercial customers, such as Universal Music and Gloversville-Johnstown Waste Water.

The existing 23kV sub-transmission system is operated in radial fashion. The main sources for the 23kV sub-transmission system are [redacted] and [redacted] substations. The 23kV sub-transmission system supplies power to a few small 4kV and 13.2kV distribution substations, such as [redacted]

Over half of the Mohawk study area is located within Adirondack Park Preserve. The Mohawk river crosses the region from east to west along the interstate I-90. There are also several lakes in this area such as the Great Sacandaga and Caroga lakes. These resources must be taken into consideration when proposing new lines and substations in this area as they can impact the feasibility of such projects.

Figure II-7

[redacted]

Table II-20
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
65	32	55,638	175 MVA

Table II-21
Major Electrical Facilities (Substations)

Substations			
Amsterdam 326	Canajoharie 31	Caroga Lake 219	Center St. 379
Charley Lake 41	Chruch St. 43	Clinton 366	Ephratah 18
Gilmantown Rd 154	Gloversville 72	Guy Park 239	Hill St. 311
Inghams 20	Johnstown 61	Market Hill 324	Marshville 299
Mayfield 356	MECO 318	Northville 332	Rotterdam 138
St. Johnsville 335	Stoner 358	Vail Mills 392	Wells 208

Table II-22
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Amsterdam	Schenectady International	3
Amsterdam	Ephratah	7
Canajoharie	Marshville	8
Gloversville	Hill St.	3
Gloversville	Canajoharie	6
Hill St.	MECO	4
Johnstown	Market Hill	8
Market Hill	Amsterdam	11
Mayfield	MECO	7
Mayfield	Vail Mills	9
MECO	Johnstown	12
Northville	Mayfield	8
Schenectady International	Rotterdam	4
Ephratah	Caroga	2
Northville	Wells	1
Wells	Gilmantown Rd.	2

Issues Identified (2009 - 2015)

Future load growth is expected outside of the Amsterdam area in the Florida Industrial Park. Beech Nut, which has been a long term customer in the Canajoharie area, is relocating its facilities to this park and is projecting to be fully installed by the end of 2010. Target is another existing customer in this park that has expansion projects expected for completion within the next couple of years. A project to extend a nearby distribution feeder to support the growth in the park was set forth in the 2009 annual plan update.

Other concerns in this area include loading on a distribution feeder out of [redacted] substation. A project to extend a nearby feeder and convert pockets of 4kV in the area was proposed as part of the 2008 annual plan update and is currently in progress.

Finally, significant asset replacement projects to address flooding concerns at the [redacted] substation, part of the Mohawk River flood plain, are underway. Until these projects are fully completed, the risk of potential flooding at this location still remains.

Table II-23
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	0	0	0	0

Table II-24
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The Table below shows recommended improvements.

Table II-25
Project Level Detail of Improvements by Year

Need Year	Summary Level Scope
2010	Customer Driven - Extend [redacted] feeder and add tie with existing [redacted]

New York East – Northeast

The Northeast study area extends approximately 90 miles north along the western border of Vermont, from Cambridge in the south to Westport in the north and extends approximately 45 miles to the west at its widest point to Indian Lake, in the Adirondack Forest Preserve. The area incorporates the southeastern section of the Adirondack Preserve. Much of the area load is concentrated in the south of the study area, along Interstate I-87 and US Route 9, particularly in the Towns of Ballston Spa, Saratoga Springs and Glen Falls. Some of these areas offer summer recreation and see a spike in load during the summer months.

The 115 kV system runs in a north-south direction on both sides of Lake George. [redacted] There is an extensive 35 kV system in the northwestern section of the study area supplying smaller towns along interstate I-87 and Route 28.

Figure II-8
Area Map

[redacted]

Table II-26
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
111	49	144,200	458 MW

Table II-27
Major Electrical Facilities (Substation)

Substations			
Ballston #12	Crown Point #249	Birch Avenue #322	Weibel Avenue #415
Spier Falls #34	McCrea Street #272	Wilton #329	Hague Road #418
West, EJ #38	Bolton #284	Ashley #331	Ogden Brook #423
Schuylerville #39	Corinth #285	Burgoyne #337	Pottersville #424
Chestertown #42	Riparius #293	Battenkill #342	Schroon Lake #429
Comstock #48	Queensbury #295	Butler #362	Malta #443
Glens Falls #75	South Street #297	Brook Road #369	Scofield Road #450
Hudson Falls #88	Indian Lake #310	Union Street #376	Cedar #453
North Creek #122	Henry Street #316	Port Henry #385	Smith Bridge #464
Saratoga #142	Fort Gage #319	Rock City Falls #404	Farnan Road #476
Whitehall #187	Warrensburg #321	Otten #412	

Table II-28
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Dahowa	Cement Mountain	1
North Lake	Indian Creek	1
Mohican	Hudson Falls	1
Cement Mountain	Cambridge	2
Chestertown	North Creek	2
Fort Gage	Queensbury	2
Glens Falls	Henry Street	3
Hoosick	Cambridge	3
Chestertown	Schroon	3
Fort Edwards	Hudson Falls	3
Spier	Brook Road	3
Adirondack Hydro Hudson Falls	Mohican	4
Glens Falls	Ashley	5
Cement Mountain	Battenkill	5
Ballston	Mechanicville	6
Schuylerville	Battenkill	6
Spier	Corinth	6
Warrensburg	Chestertown	6
AHDC Middle Falls	Cement Mountain	7
Chestertown	North Creek	7
Queensbury	Bay Street	7
Ballston	Shore Road	8
Hoosick	Clay Hill	8
Spier	Glens Falls	8
Warrensburg	Fort Gage	8
Queensbury	Warrensburg	9
West Milton	Ballston	9
Glens Falls	Bat Street	10
Saratoga	Ballston	10
Brook Road	Ballston	11
Mohican	Glens Falls	11
Mohican	Glens Falls	12
Spier	Saratoga	12
Queensbury	Henry Street	14
Hudson Falls	McCrea Street	17

Issues Identified (2009 - 2015)

There is a major development proposed at Luther Forest, east of the Malta substation. Significant transmission infrastructure development is planned to address this new load and existing area concerns. Significant system reactive support is expected to be required. Some of the capacitors required may be installed at the distribution voltage level and some on the 115 kV system. The exact timing and location will be determined as coordinated to address the rate and location of load growth. The need for distribution infrastructure development to serve ancillary area load growth will be monitored closely and, if required, project proposals will be made in future updates of the annual capacity plan.

There are a number of single transformer stations that are supplied from the 115 kV system that are heavily loaded. Although the feeders have ties to adjacent stations, only a portion of the station load can be picked up through switching during a contingency. In the event of a substation transformer contingency, some load will remain out of service until a mobile transformer can be installed or the bank is returned to service. There are several locations where the outage exposure exceeds planning guidelines. These include [redacted] within the next 3 years and [redacted] in later years. Proposals have been developed to add a second transformer at [redacted] over the next several years.

The Glens Falls secondary network system is supplied by four 4.162kV feeders from the [redacted] substations. The Glens Falls secondary network system supplies 4MVA of load, approximately 220 customers.

Table II-29
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
5	9	6	7	1	1

Table II-30
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
4	7	6	7	N/A	N/A

Recommended Improvements

Short term feeder thermal concerns have been addressed in the 2009 annual plan. There are a number of other loading concerns that need to be addressed in later years, including feeder outage exposure concerns due to limited feeder ties. Review of these issues is on-going and the results will be included in the next Annual Capacity Plan update. The Planning efforts will coordinate with representatives of Distribution Planning, Transmission Planning, and Operations to identify a proper integrated solution to area thermal issues The current economic downturn is expected to reduce the stress on the system and allow time to resolve many of the issues associated with feeders that are projected to be heavily loaded within the next few years.

Table II-31
Project Level Details

Need Year	Summary Level Scope
2012	[redacted] - Install second transformer, switchgear, one new feeder and two station capacitor banks
2013	[redacted] - Install 2nd transformer, switchgear and rearrange distribution system
2015	Install load break at P27 I[redacted]feeder
2015	[redacted] - Install second transformer, extend structure, add cap banks and new getaways.

New York East – Schenectady

The Schenectady study area is defined by the region that includes the city of Schenectady and the suburban areas surrounding the city. This area includes a mixture of industrial, commercial and residential customers spread across downtown to suburban areas such as Niskayuna, Glenville, and Rotterdam.

The primary distribution system in Schenectady is predominantly 13.2kV with a few pockets of 4.16kV (Scotia and Rotterdam areas). All 4kV distribution substations are supplied from the local 34.5kV sub-transmission system, whereas most 13.2kV distribution substations are supplied from the local 115kV transmission system.

The Schenectady secondary network system is supplied by five 13.2kV feeders from the [redacted]substation. The Schenectady secondary network system supplies 16MVA of load, approximately 1120 customers.

[redacted]are the main sources for the local 34.5kV sub-transmission system, which is operated in loop fashion. Besides supplying power to all 4kV and a few 13.2kV distribution substations, the 34.5kV sub-transmission system also serves a few industrial and commercial customers in the area, such as Knolls Atomic, CBS, and Golub Corporation. Critical load in Schenectady includes the two main hospitals Ellis and St Claire's.

Figure II-9
Area Map

[redacted]

Table II-32
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
56	25	58,095	205 MVA

Table II-33
Major Electrical Facilities (Substation)

Substations			
Burdeck St 265	Chrisler Ave 257	Curry Rd 365	Emmet 256
Front St 360	Karner 317	Lynn St 320	McClellan St 304
Rosa Rd 137	Rotterdam 138	Scotia 255	Watt St 230
Weaver St 245	Woodlawn WDN		

Table II-34
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Emmet	McCellan St	10
Emmet	Woodlawn	13
Karner	Patroon	5
Knolls	Vischer	5
Lynn St	Woodlawn	1
McCellan St	Bevis Hill	11
Rosa Rd	Knolls	1
Rosa Rd.	Bevis Hill	2
Rotterdam	Scotia	32
Rotterdam	Lynn St	34
Rotterdam	Weaver	36
Scotia	Rosa Rd.	6
Vischer	Woodlawn	3
Weaver St.	Emmet	9
Woodlawn	Karner	14

Issues Identified (2009 - 2015)

Future load growth is expected in the city of Schenectady due to the expansion of Ellis Hospital, which is supplied from the local distribution system. Other growth is anticipated in the downtown area as a result of city revitalization projects.

Single contingencies on the 34.5kV sub-transmission system in this area could potentially result in unserved load. However, manual switching can be utilized in response to the contingency events and projected exposure does not exceed design guideline limits. Contingency unserved load exposure on the 34.5kV sub-transmission system will be monitored and reviewed closely in future Capacity Plan updates.

Table II-35
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
2	6	1	1	0	1

Table II-36
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	1	0	0	0	0

Recommended Improvements

To address normal loading concerns on feeders out of [redacted] substations, underground cable getaway replacements were recommended in prior annual plan reviews. Field switching has been recommended to address normal loading concerns on feeders out of [redacted]. Finally, normal loading concerns on [redacted] that were identified in the 2008 Annual Plan update will be addressed via field switching post conversion of 4kV pockets (all expected prior to the end of FY10).

Table II-37
Project Level Detail

Need Year	Summary Level Scope
2010	Transfer 80A by switching from [redacted] to [redacted] and 14A from [redacted] to [redacted] feeder.
2013	Install 900 kVAR capacitor bank on [redacted] feeder [redacted] to provide approximately 432 kVA of relief
2014	Replace 700 ft of underground getaway with 1000 Cu

New York East – Schoharie

The Schoharie study area is defined by the region west of Schenectady that includes towns and villages along the I-88 and Rt 20 corridors, such as Delanson, Schoharie, Cobleskill, Schenevous, and Sharon Springs. This area is mostly rural comprised mainly of residential customers and farms with a few commercial and industrial customers.

The primary distribution system in Schoharie is predominantly 13.2kV with areas of 4.8kV (Cobleskill, Worcester, and Schenevous areas). Most distribution substations in this region are supplied from the local 23kV and 69kV sub-transmission system.

[redacted] substations are the main sources for the local 69kV sub-transmission system, which is operated in loop fashion. The 69kV sub-transmission system supplies power to both 4kV and 13.2kV distribution substations, besides a few industrial and commercial customers, such as Guilford Mills and Suny Cobleskill.

The existing 23kV sub-transmission system in Schoharie is operated in radial fashion. The main source for the 23kV sub-transmission system is [redacted] The 23kV sub-transmission system supplies power to a few small 4kV distribution substations, such as East Worcester, Worcester, and Schenevous.

Figure II-10
Area Map

[redacted]

Table II-38
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
18	13	21,469	46 MVA

Table II-39
Major Electrical Facilities (Substation)

Substations			
Cobleskill 214	Delanson 269	East Springfield 477	East Worcester 60
Grand St 433	Middleburg 390	Schenevus 261	Schoharie 234
Sharon 363	Summit 347	Worcester 189	

Table II-40
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Cobleskill	Summit	5
Cobleskill	Schoharie	6
Marshville	Sharon	16
Rotterdam	Schoharie	18
Schenevus	Summit	3
Sharon	Cobleskill	17

Issues Identified for (2009 – 2015)

No significant load growth is expected for this area at this time and no loading concerns were identified in this year's Annual Capacity Plan review.

Recommended Improvements

No improvements are necessary at this time.

New York Central – Cazenovia

Cazenovia is a very rural area with the Village of Cazenovia and the Cazenovia Industrial Park being the only larger loads. The distribution system consists of one 34.5-13.2kV, and four 34.5-5kV substations.

Figure II-11

[redacted]

Table II-41
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
9	5	6468	16 MW

Table II-42
Major Electrical Facilities (Substations)

Substations			
Ballina 221	Cazenovia 220	Chittenango 16	Perryville 50
Ridge Road 219			

Table II-43
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Pebble Hill	Rathbun	27
Minoa	Whitman	28

Issues Identified (2011 – 2015)

The [redacted] Substation is presently loaded above summer normal capabilities during peak load periods. A project which will reduce this substation's loading was recommended in the 2008 Capacity Plan, has been approved, and is underway.

The only significant physical constraint on infrastructure development in the area is in the [redacted] area consisting of residential load spread around the lake.

The future load increases for the Cazenovia area will be predominantly residential housing. If loading concerns arise in the future on a 34.5-5kV substation, there is sufficient 13.2kV feeder capacity in the area to allow conversion and transfer of load without the need of a major new source.

Table II-44
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	1	0	0	0

Table II-45
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The table below provides a list of recommended improvements.

Table II-46
Project Level Detail

Need Year	Summary Level Scope
2009	[redacted] convert & transfer 2200Ft to [redacted] 53

New York Central – Cortland

The Cortland study area is defined by the region that includes the city of Cortland and the surrounding towns and villages. It is located in central New York between Syracuse and Binghamton.

The primary distribution system voltages in Cortland are 13.2kV and 4.8kV. Most of the area is fed from a 34.5kV sub-transmission system supplied out of the [redacted] substations.

The Cortland secondary network system is supplied by three 4.8kV feeders from the [redacted] substations. The Cortland secondary network system supplies 2MVA of load, representing approximately 374 customers.

Figure II-12
Area Map

[redacted]

Table II-47
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
30	19	32,786	92 MVA

Table II-48
Major Electric Facilities (Substations)

Substations			
Cardiff 13	Cortland 502	Cuyler 24	Delphi 262
Fabius 556	Fisher Ave 270	Homer 129	Labrador 230
Lords Hill 150	Lorings 276	Mcgraw 228	Miller St. 117
Starr Rd. 334	Truxton 74	Tuller Hill 246	Tully Center 278

Table II-49
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Cortland	Cortland	20
Cortland	Cortland	21
Cortland	Cortland	23
Labrador	Rathbun	39
Pebble Hill	Tilden/Tully Tap	32
Tilden	Tully Tap	24

Issues Identified (2009 – 2015)

One normal feeder overload is forecasted in the area that will be resolved by the upgrade of a step down transformer.

A significant outage exposure risk exists for the loss of the [redacted] transformer. A project proposal to add a second transformer at this substation to eliminate this risk has been included in this plan.

Table II-50
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	0	0	0	0

Table II-51
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	1	1	0	0

Recommended Improvements

After the proposed work in this area is complete no further planning concerns are forecasted within the 5 year planning horizon.

Table II-52
Project Detail

Need Year	Summary Level Scope
2009	Convert [redacted] & [redacted] and transfer to [redacted] [redacted] 54
2009	Cortland 02 convert & transfer to [redacted] 54
2012	Add second transformer at [redacted] substation
2012	Replace the [redacted] 115-34.5kV transformer with a 115-13.2kV transformer

New York Central – East Syracuse

East Syracuse consists of the industrial suburb of the City of Syracuse. The distribution system consists of one 115-34.5kV, three 115-13.2kV and three 34.5-5kV substations.

Figure II-13
Area Map

[redacted]

Table II-53
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
25	10	16,026	102 MW

Table II-54
Major Electrical Facilities (Substations)

Substations			
BRIDGE STREET 295	EAST MALLOY 151	EAST SYRACUSE 27	FLY ROAD 261
MINOA 44	SPRINGFIELD 167		

Table II-55
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Burnet Ave.	Headson	34
Headson	Tilden	38
Headson	Minoa	33
Headson	Pebble Hill	26
Minoa	Whitman	28
Teall		29
Teall	Headson	31

Issues Identified (2009 - 2015)

There is only one feeder loading concern ([redacted]) that can be resolved with a reconductoring project. There are no outage exposure issues forecasted during the 5 year study horizon. The transmission is adequate and the only man-made barriers to distribution system infrastructure development are Interstate 690 and Interstate 481 going through the area.

The 115-13.2kV substations are built with dual transmission supply and designed to accommodate a second transformer.

Table II-56
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-57
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The table below provides the recommended improvement for this area.

Table II-58
Project Level Detail

Need Year	Summary Level Scope
2009	[redacted] reconductor 1/0 CU

New York Central – Manilus and Fayetteville

The Manilus Fayetteville area is a residential suburb of Syracuse. The distribution system is comprised of one 115-34.5kV, four 115-13.2kV and one 34.5-5kV substation. Most new load additions to the area are new residential developments. The [redacted] 34.5-5kV transformer has failed and it was recommended to convert the feeders and transfer to the 13.2kV system. This conversion will be completed in 2009.

Figure II-14

[redacted]

Table II-59
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
17	6	22,413	104 MW

Table II-60
Major Electrical Facilities (Substation)

Substations			
Butternut 255	Duguid 265	Fayetteville 28	Pebble Hill 290
Southwood 244			

Table II-61
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Burnet Ave	Headson	34
Headson	Tilden	38
Headson	Minoa	33
Headson	Pebble Hill	26
Teall		29
Teall	Headson	31

Issues Identified (2011 – 2015)

The main concern in this area relates to the [redacted] Substation which is supplied via a radial 6 mile long 115kV transmission line. The station has one transformer which is loaded to 35 MVA, or 90 percent of its summer normal rating. For loss of this transformer approximately 20MVA of load may remain out of service until a mobile transformer is installed or the bank is returned to service. The proposed solution is to install a second circuit for the 115kV transmission line supply and to add a second transformer and two new feeders. The area around the substation has experienced significant residential development and for a section of the 115kV transmission supply line there is a NY State Park present on both sides of the line right of way. As such, there are expected to be permitting challenges associated with this proposed facility expansion/development. Distribution Planning and Transmission Planning are working collaboratively to further evaluate and develop the correct long term solution for this concern.

Table II-62
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-63
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	2	1	1	0	0

Recommended Improvements

The table below provides a list of recommended improvements for this area.

Table II-64
Project Detail Level

Need Year	Summary Level Scope
2008	[redacted] retire feeders due to transformer failure
2012	Create a tie between Fly 54 & Butternut 55
2016	Install a second transformer at the [redacted] Sub and two distribution feeders

New York Central – Nicholville and Malone

The Nicholville - Malone area has approximately 18,535 customers with a peak load of 47MW.

The study area has a total of twenty seven feeders (twenty 4.8kV and seven 13.2kV feeders). The distribution substations are primarily supplied from the 34.5kV system with exception of [redacted] that are served off 115kV system. The main supplies for the 34kV Sub transmission system are [redacted] substations. It is operated as a radial system although the system is a loop design. There are also a two hydroelectric facilities connected to the system ([redacted] stations).

Because of the limited capacity of the Nicholville – Malone 34.5kV system a new substation (Akwesasne) was built to improve the reliability and provide additional capacity to the 34.5kV system to accommodate load growth in the area.

Figure II-15

[redacted]

Table II-65
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
27	19	18,535	47 MW

Table II-66
Major Electrical Facilities (Substation)

Substations			
AKWESASNE	ELM STREET	NICHOLVILLE	ROOSEVELT ROAD
BOMBAY	FORT COVINGTON	NORTH BANGOR	ST. REGIS
BRASHER	MALONE	NORTH BOMBAY	WESTVILLE
CHASM FALLS	MOIRA	NORTH LAWRENCE	

Table II-67
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Nicholville	North Bangor	21
Spencer Corners	Bombay	22
Nicholville	Bombay	23
Malone	Chasm Falls	23
Malone	Spencer Corners	24
Malone	Spencer Corners	26
Akwesasne	Fort Convington	26
Akwesasne	Nicholville	23

Issues Identified (2009 - 2015)

There is a new 10 MW service request to serve the Mohawk tribe's new casino where the existing casino is already located. With this additional load development, the loss of [redacted] would result in contingency unserved load just at planning guideline 240MWhr threshold in 2015 (assumes that during contingency North Bombay, Bombay, Forth Covington, Westville, North Bangor and Moira are served from Malone Substation). Load development will be monitored closely and the 2010 Annual Plan review will identify any corrective action that may be required to address this concern.

There is only one feeder loaded above 90 percent summer thermal rating. No normal thermal overloading concerns were identified during 2009 annual plan review in this study area.

Table II-68
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-69
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

There are no recommended improvements at this time for this area.

New York Central – North Syracuse

North Syracuse area is the northern suburb of the City of Syracuse. It has received the majority of the new housing development in the Syracuse metropolitan area. The distribution system consists of one 115-34.5kV, seven 115-13.2kV, and five 34.5-5kV stations.

Figure II-16
Area Map

[redacted]

Table II-70
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
49	18	65,824	300 MW

Table II-71
Major Electrical Facilities (Substation)

Substations			
Bartell 325	Belmont 260	Brewerton 7	Buckley 140
Euclid 267	Galeville 213	Hopkins 253	Lysander 297
Pine Grove 59	Seventh North 231	Sorrell Hill 269	Stiles 58
Woodard 233			

Table II-72
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Baldwinsville	Solvay	22
Solvay		22
Mallory	Cicero	33
Woodard		24
Woodard		28
Woodard	Baldwinsville	29
Woodard	Crouse Hinds	26
Woodard	Teall	32
Teall		32
Woodard	Ash St.	27

Issues Identified (2009 - 2015)

A concern in the North Syracuse area involves the contingency response capability on [redacted] substation feeders. A new substation was approved and will be completed in 2012. It will be located in the middle of the four most heavily loaded substations so that feeder and transformer loading can be reduced and feeder ties established that will enable adequate contingency response. Switched capacitors will be installed to reduce the demand loading on several 13.2kV feeders.

The physical barriers for system development in the North Syracuse area are the two interstates highways, I-81 and I-90.

Table II-73
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	2	0	0	0	0

Table II-74
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
10	14	3	5	0	0

Recommended Improvements

The table below provides a list of recommended improvements for this area.

Table II-75
Project Level Detail

Need Year	Summary Level Scope
2008	[redacted] convert & transfer to [redacted].
2009	[redacted] 56 overloaded step down transformer.
2009	[redacted] new substation and four feeders
2009	[redacted]

New York Central – Oneida

The Oneida area is comprised of the City of Oneida and the Village of Conastota. There are very few loading issues in the Oneida area. In the City of Oneida, Oneida Hospital has a dual distribution supply. Across the street from the hospital, H.P.Hood Dairy Products Inc. (a 4 MVA load) also has dual distribution supply. The Village of Canastota which is located in western section of the Oneida area has several large commercial and industrial customers that require special attention to their service reliability. Canastota Industrial Park, Owl Wire and Cable, Inc., and Die Molding Inc. are some of these industrial customers in this area.

A geographic constraint on distribution system infrastructure development is the long distance from other substations and consequently the operational concerns that result from the lack of feeder ties. There has been an effort made to improve feeder ties between the two substations [redacted] Although work on these ties has been completed, developing them was challenging due to Interstate 90 which runs between the two substations.

Lennox substation is a step down transformer off the 13.2 feeders from Oneida. This step down transformer serves three 4kV feeders which are the only 4kV feeders in the area. The Madison County Solid Waste Authority will bring on line in 2009 a 2MW distribution generator at their landfill site south of the City of Oneida.

Figure II-17

[redacted]

Table II-76
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
18	4	21,172	73 MW

Table II-77
Major Electrical Facilities (Substations)

Substations			
ONEIDA 501	PETERBORO 514		

Table II-78
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
N/A		

Issues Identified (2009 - 2015)

No issues were identified.

Recommended Improvements

There are no recommendations at this time for this area.

New York Central – Rome

The Rome area has approximately 27,484 customers with a total peak load demand of 87 MW.

There are thirty 4.8kV feeders and seventeen 13.2kV feeders in the study area. All distribution substations are supplied from 115kV system as a result there are no sub transmission lines in the area.

Figure II-18
Area Map

[redacted]

Table II-79
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
27	6	27484	87 MW

Table II-80
Major Electrical Facilities (Substation)

Substations			
LEVITT	LEHIGH	MADISON	ROME
TURIN ROAD			

Table II-81
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
N/A	N/A	N/A

Issues Identified (2009 – 2015)

No load related issues were identified during 2009 annual plan review in this study area. There is only one feeder loaded above 90 percent summer normal and the transformers loading are all below 90 percent summer normal rating.

[redacted] is a single ended substation with three feeders. The [redacted] feeder only has feeder ties with [redacted] and [redacted] but there is a project (C28607) to build new feeder tie with [redacted] in order to provide back up in a event of outage of the [redacted] transformer.

Recommended Improvements

One recommended improvement is provided in the table below.

Table II-82
Project Level Detail

Need Year	Summary Level Scope
2010	Build a new feeder tie between [redacted] feeders

New York Central – St. Lawrence

The St. Lawrence area has approximately 44,153 customers with a total peak load demand of 116 MVA.

There are twenty six 4.8kV feeders and thirty 13.2kV feeders in this study area. The distribution substations are mainly supplied from 23kV and 34.5kV systems with exception of four substations that are served off 115kV system; [redacted]. The main supply for the 23kV Sub transmission system are [redacted]k and for the 34.5 kV Sub transmission system is [redacted].

Figure II-19

[redacted]

Table II-83
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
56	35	44153	116 MW

Table II-84
Major Electrical Facilities (Substations)

Substations			
BALMAT	EDWARDS	LITTLE RIVER	PARISHVILLE
BRADY	FINE	MCADOO	STAR LAKE
BRIER HILL	HAMMOND	MORRISTOWN	STATE STREET
CORNING	HEUVELTON	NEWTON FALLS	BROWN FALLS
DAVID	HIGLEY	NORTH GOUVERNEUR	LITTLE RIVER
DEKALB	LAWRENCE AVE	NORWOOD	MCINTYRE
EAST NORFOLK	LISBON	OGDENSBURG	MINE RD.
NORFOLK			

Table II-85
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Colony	Browns Falls	21
Browns Falls	Newton Falls	22
Colony	South Edwards	22
Emeryville	Gouverneur Talc. Co.	2
Mcintyre	David	21
Norfolk	Norwood	21
Emeryville	Mine Rd.	23
Mcintyre	Heuvelton	23
Balmat	Emeryville	24
Mcintyre	Hammond	24
Lisbon	Heuvelton	25
State St.	Little River	26
Balmat	Fowler	27
Mine Rd.	Colony	28

Issues Identified (2009 – 2015)

[redacted] 46/4.8kV is a single ended Station that is fed from the 46 kV [redacted] radial line out of [redacted] sub. Thermal loading concerns were identified on the transformer at this substation in 2007 and there is an ongoing project (C27323) to replace the existing 1.75 MVA bank with a conventional 46/4.8kV 3.75 MVA transformer Bank. This project is expected to be complete before the end of FY10. Feeder reactive support has been identified to address localized voltage performance concerns.

No additional load related issues were identified during 2009 annual plan review in this study area.

There are only one feeder and three transformers loaded above 90 percent summer thermal rating in this study area.

Recommended Improvements

The following improvements are recommended.

Table II-86
Project Level Detail

Need Year	Summary Level Scope
2009	[redacted] Capacitor Bank Installation
2009	[redacted]eeder capacitor installation.

New York Central – Syracuse

The Syracuse study area is made up of the city of Syracuse in central New York as well as the village of Skaneateles about 20 miles southwest of the city.

The primary distribution system voltages in the area are 13.2kV and 4.16kV. There is also a 12kV network fed out of [redacted]. Most of the area is fed from a 34.5kV sub-transmission system supplied out of [redacted]. There is also some 13kV fed directly from the 115kV transmission system.

Syracuse has two secondary network systems. The Ash St. secondary network system is supplied by ten 13.2kV feeders from the [redacted]substation. The Ash St. secondary network system supplies 32MVA of load, approximately 1160 customers. The Temple St. secondary network system is supplied by seven 13.2kV feeders from the [redacted]substation. The Temple St. secondary network system supplies 20MVA of load, approximately 170 customers.

Figure II-20

[redacted]

Table II-87
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
99	37	58,100	330 MVA

Table II-88
Major Electrical Facilities (Substation)

Substations			
Ash St. 223	Brighton 8	Dorwin 26	E. Malloy 151
Fayette St. 28	Hancock 137	Hancock#2 138	Jewett Rd. 291
Midler 145	Niles 294	Park St. 144	Peat St. 250
Pompey 120	Rock Cut 286	Sand Rd. 131	Sand Rd.#2 141
Sentinel Heights 128	Southwood 244	Teall 72	Temple 243
	Solvey	Tilden	

Table II-89
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	**To**	**Supply Line Number**
Ash St.	Burnet	30
Ash St.	Burnet	33
Ash St.	Carousel	25
Ash St.	Carousel	29
Ash St.	McBride	24
Ash St.	McBride	23
Ash St.	Solvay	28
Brighton	Tilden	37
Brighton	Tilden	38
Elbridge	Jewett	31
Fayette	Ash St.	39
Fayette	Ash St.	38
Fayette	Solvay	36
Fayette	Solvay	37
McBride	Brighton	20
McBride	Brighton	22
McBride	University	25
McBride	University	33
Niles Tap		509
Solvay		26
Solvay		27
Teall	Ley Creek Treatment Plant	25
Teall	Syracuse China	28

Issues Identified (2009 – 2015)

There are no projected normal overloads in this area in the 5 year planning horizon.

Four feeders are found to have outage exposure concerns including loss of [redacted]. There are also two transformers with outage exposure concerns including loss of [redacted].

Finally, an asset concern issue has surfaced regarding the condition of the 34kV supply line between [redacted] This line will need to either be rebuilt or retired and is currently under study for alternative options that could be weighed against a full rebuild.

The planning review for the outage exposure concerns and the development of long term plans for the [redacted] line is on going Distribution planning is coordinating with representatives of Transmission Planning and Operations to identify a proper integrated solution.

Table II-90
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-91
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
4	4	2	2	0	0

Recommended Improvements

The following improvements are recommended for this area.

Table II-92
Project Level Detail

Need Year	Summary Level Scope
2008	[redacted] rebuild & convert to reduce load on step down transformer.
2009	[redacted] convert and transfer Oak St.load to [redacted]

New York Central – Tri Lakes

The Tri lakes area has approximately 11,331 customers with a total peak load demand of 24.72 MVA.

There are twenty nine 4.8kV, two 2.4kV feeders and six 13.2kV feeders in the study area. Most of the distribution substations are supplied from the 46kV sub transmission system with the exception of two substations that are served off the 115kV system [redacted] substations. The source for the 46kV Sub transmission system in the area is the [redacted] substation.

There are two municipal electric companies supplied via lines in the Tri-Lakes area. Lake Placid Municipal is supplied by the [redacted]. Tupper Lake Municipal is supplied by the new [redacted].

Figure II-21

[redacted]

Table II-93
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
17	16	11331	24.72 MW

Table II-94
Major Electrical Facilities (Substation)

Substations			
AUSABLE FORKS	GILPIN BAY	PAUL SMITHS	SILVER LAKE
BLOOMINGDALE	LAKE COLBY	PIERCEFIELD	UNION
FRANKLIN FALLS	LOON LAKE	RAYBROOK	LAKE COLBY
GABRIELS	MERRILLVILLE	RIVERVIEW	

Table II-95
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Lake Clear	Lake Colby	30
Lake Colby	Franklin	31
Union Falls	Franklin	34
Union Falls	Lake Clear	35
Union Falls	Ausable Forks	36
High Falls	Union Falls	37
Lake Clear	Tupper Lake	38
Piercefield	Tupper Lake	39

Issues Identified (2011 - 2015)

No load related issues were identified during the 2009 annual plan review in this study area.

There is only one feeder that is loaded above 90 percent summer thermal rating.

Recommended Improvements

No improvements are recommended for this area.

New York Central – Utica

There are no loading or outage exposure issues in the Utica area. The load center for this area is the City of Utica. The distribution system consists of four 115-46kV, ten 115-13.2kV, four 46-13.2kV and seven 46- 5kV substations.

The Utica secondary network system is supplied by ten 13.2kV feeders from the Riverside and Trinity substations. The Utica secondary network system supplies 9MVA of load, representing approximately 471 customers.

A small portion of the underground network consists of a radial system, connected to overhead lines, that serves customers in the area of the 5kV. The City of Utica owns the majority of the network manholes and duct lines; hence, National Grid is a tenant.

Figure II-22

[redacted]

Table II-96
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
82	35	91,119	300 MW

Table II-97
Major Electrical Facilities (Substation)

Substations			
ARNOLD 656	CAVANAUGH RD. 616	CHADWICKS 668	CLINTON 604
CONKLING 652	DEBALSO 684	DEERFIELD 606	FRANKFORT 677
MIDDLEVILLE 666	PLEASANT 664	POLAND 622	ROCK CITY 623
SALISBURY 678	SCHUYLER 663	SHERMAN 333	SO.WASHINGTON 614
STITTVILLE 670	TERMINAL 651	VALLEY 594	WALESVILLE 331
WEST HERKIMER 676	WHITESBORO 632	YAHNUNDASIS 646	

Table II-98
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Deerfield	Schuyler	22
Deerfield	Whitesboro	26
Pleasant	Schuyler	26
Schuyler	Valley	21
Schuyler	Valley	24
Trenton	Deerfield	21
Trenton	Deerfield	27
Trenton	Middleville	24
Trenton	Prospect	23
Trenton	Whitesboro	25
Valley	Inghams	26
Valley	Inghams	27
Whitesboro	Schuyler	29
Whitesboro	Homogenous Metals Tap	29
Yahnundasis	Clinton	27
Yahnundasis	Pleasant	25
Yahnundasis	Westmoreland	24
Yahnundasis	Whitesboro	23

Issues Identified (2009 - 2015)

The [redacted] Substation is served with a single circuit radial 115kV transmission line. There is the potential for outage exposure for loss of this line, however there are sufficient feeder ties to maintain the risk within acceptable levels.

The Mohawk River and Interstate 90 run through the middle of Utica area which are constraints for infrastructure development.

Table II-99
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-100
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	1	1

Recommended Improvements

The common mode failure of the [redacted] lines, which are on common structures and have a history of simultaneous outages, results in overload of the [redacted] ine. It is recommended that a six miles section of the [redacted] line be re-conductored from 4/0 ACSR to 336.4 ACSR and resolve the contingency loading concern.

Table II-101
Project Level Detail

Need Year	Summary Level Scope
2010	Reconductor 6 miles of [redacted].

New York Central – Volney

The Volney area serves two Cities: Oswego and Fulton. The distribution system consists of four 115-34.5kV, seven 115-13.2kV, five 34.5-13.2kV and nine 34.5-5kV lines.

Figure II-23

[redacted]

Table II-102
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
43	28	53,753	156 MW

Table II-103
Major Electrical Facilities (Substation)

Substations			
CENTRAL SQUARE 15	CLEVELAND 11	COLOSSE 321	CONSTANTIA 19
EAST FULTON 100	EAST PULASKI 324	FAIRDALE 135	GILBERT MILLS 247
GRANBY CENTER 293	LAKE ROAD 299	LIGHTHOUSE HILL 61	MEXICO 43
NEW HAVEN 256	PALOMA 254	PARISH 49	PHOENIX 51
SANDY CREEK 66	THIRD STREET 216	WEST CLEVELAND 326	WEST MONROE 274
WHITAKER 296	WINE CREEK 283	MALLORY 125	CURTIS 224
BRISHOL HILL 109	OSWEGO 200		

Table II-104
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Bristol Hill	Fay St.	25
Bristol Hill	Phoenix	23
Phoenix	Phoenix Hydro	23
Bristol Hill	Varick	202
Minetto Tap		202
Curtis St	Bristol Hill	28
Fairdale Tap		28
Fay St	Curtis St	26
Fay St		24
High Dam	Varick	21
Lighthouse Hill		22
Mallory		22
Mallory	Cleveland	31
Oswego Steam	Oswego City Pump	26
Oswego Steam	Varick	207

Issues Identified (2011 - 2015)

Two loading issues in the Volney area have been identified. On the [redacted] which picked up load by step down transformers from the [redacted] transformer which failed in 2004, a step down transformer is forecast to serve load at 126 percent of its rating. In addition, the [redacted] feeder is forecast to overload as the result of recent residential load growth in the area. This issue will be addressed by local conversions and switching load to the [redacted] Geographical issues result in the [redacted] feeders having few feeder ties. The City on Oswego has Lake Ontario to the north, the franchise boundary to the west and no feeder ties with to the south. Lack of feeder ties results in outage exposure risks at Paloma. A proposal to install a second transformer at [redacted] substation has been developed.

A potential natural barrier to distribution system infrastructure development in the Volney area is the Oswego River.

Table II-105
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-106
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	1	1	0	0

Recommended Improvements

The table below provides details on recommended improvements in this area.

Table II-107
Project Level Detail

Need Year	Summary Level Scope
2011	Rebuild and convert 5600 ft of 5kV line
2011	Convert and create a tie between the [redacted]
2015	Install a second transformer and two feeder positions

New York Central – West Syracuse

West Syracuse is a suburb of the City of Syracuse. This area has a new mall and several new stores such as Target and Walmart. The distribution system is comprised of one 115-34.5kV, two 115-13.2kV and three 34.5-5kV substations.

Figure II-24
Area Map

[redacted]

Table II-108
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
22	7	21,049	87 MW

Table II-109
Major Electrical Facilities (Substation)

Substations			
CAMILLUS 10	GLENWOOD 227	HARRIS ROAD 235	HINSDALE 218
MILTON AVE 266	WESTVALE 133		

Table II-110
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Elbridge	Marcellus	30
Harris Rd.	Tilden	33
Harris Rd.	Tilden	21
Solvay	Harris Rd	20
Solvay	Harris Rd	34
Solvay		35
Solvay		22

Issues Identified (2009 - 2015)

The 34.5-5kV substations are located along the main highway where all the commercial loads are located. As the commercial load has increased, conversion and transfer of load to the 13.2kV feeders has been required. The 13.2kV feeders near the 5kV feeders are heavily loaded. One 13.2kV feeder [redacted] will need to be relieved in 2012.

This area is located on the West end of the Central NY franchise. The only feeders ties are toward the City of Syracuse. Both the 115-13.2kV substations [redacted] substations have outage exposure concerns which could be resolved by the installation of a second transformer at [redacted]

The sub-transmission system in this area has no loading or outage exposure violations.

Table II-111
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	1	0	1	0	0

Table II-112
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	2	2	0	0

Recommended Improvements

The table below provides details on recommended improvements in the area.

Table II-113
Project Level Detail

Need Year	Summary Level Scope
2009	C00253 change to C31128. [redacted] Convert & transfer to [redacted]
2012	[redacted] build a 1700 ft on [redacted] between [redacted] and [redacted]
2016	Install a second transformer at the [redacted] Substation and two feeder positions.

New York Central – WLOF

The WLOF area has approximately 81,303 customers with a peak load of 253 MW.

This study area has total of thirty six 4.8kV feeders and thirty nine 13.2kV feeders. The distribution substations are primarily supplied from 23kV and 46kV systems with the exception of a few substations that are served off the 115kV system. The main sources to the 23kV Sub transmission system are [redacted] substations and [redacted] for the 46kV sub-transmission system.

The Watertown secondary network system is supplied by five 4.8kV feeders from the [redacted] substation. The Watertown secondary network system supplies 5MVA of load, representing approximately 440 customers.

Figure II-25

[redacted]

Table II-114
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
75	37	81,303	253 MW

Table II-115
Major Electrical Facilities (Substation)

Substations			
ALDER CREEK	COFFEEN	INDIAN RIVER	MILL STREET
ANTWERP	COLLINSVILLE	LERAY	NORTH CARTHAGE
BREMEN	EAGLE BAY	LOWVILLE	OLD FORGE
CARTHAGE	EAST WATERTOWN	LYME	PORT LEYDEN
PORTAGE STREET	SO. PHILADELPHIA	THOUSAND ISLANDS	BLACK RIVER
RAQUETTE LAKE	SUNDAY CREEK	WEST ADAMS	BOONVILLE
SEWALLS ISLAND	TAYLORVILLE	WHITE LAKE	INDIAN RIVER

Table II-116
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Old Forge	Raquette Lake	21
Boonville	Alder Creek	22
Alder Creek	Old Forge	23
Carthage	High Falls	21
Mill St.	Black River	21
South Philadelphia	Thersa	21
Black River	Black River Hydro	22
Carthage	Taylorville	22
Lowville	Boonville	22
Beaver Falls	Taylorville	23
Carthage	North Carthage	24
Leray	Black River	24
South Philadelphia	Antwerp	24
Taylorville	Effley	24
Belfort	Taylorville	25
Coffeen	Dexter	25
South Philadelphia	Indian River	25
Carthage	Copenhagen	26
Coffeen	Mill St.	26
High Falls	Taylorville	26
Deferiet	Herrings	27
Herring	Carthage	28
Deferiet	North Carthage	29

Issues Identified (2009 – 2015)

Only one feeder in the area ([redacted] is projected to exceed the summer normal thermal rating. This concern can be relieve by a transfer of load to [redacted]

Under contingency scenarios, both [redacted] 115/13.2 kV transformers could exceed their summer emergency rating during peak load conditions. If a contingency were to occur at peak, load would need to be transferred or shed, but the outage exposure is within acceptable limits. Similarly, the [redacted] 46/4.8kV T1 transformer is projected to exceed its summer emergency rating but outage exposures are acceptable.

The [redacted] is projected to exceed its summer emergency thermal rating by 2012 due to excess generation on the line from [redacted]. As a short term solution, it is recommended to keep the generation on [redacted] within the line limits. The long term plan being considered involves reconductoring the overhead section as recommended in the annual plan review. The reconductoring job will be approximately 6.33 miles.

The [redacted] is projected to exceed its summer normal rating by 2012. An existing reliability project (C29441) to reconductor the line will address this concern and it is estimated to be completed in 2011.

[redacted] 46/4.8kV is a single ended substation that is fed from the 46 kV [redacted] radial line out of [redacted] subtation. Transformer loading concerns were identified in past reviews and there is an ongoing project (C27322) to replace the existing 1.1 MVA bank with a 46/4.8kV 2.5 MVA [redacted] transformer. There are no feeder ties with the 39861 feeder because the station is located at the end of National Grid service territory.

Table II-117
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	2	0	1	1	1

Table II-118
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The table below provides details on recommended improvements in the area.

Table II-119
Project Level Detail

Need Year	Summary Level Scope
2009	[redacted] feeder capacitor bank installation.
2009	[redacted] capacitor banks installation
2009	[redacted] feeder capacitor bank installation.
2009	[redacted] feeder [redacted] capacitor bank installation
2012	Replacement of [redacted] 23/4.8kV 3-500kVA Transformer with 3.75 MVA Transformer Bank.
2015	Transfer 43 A from [redacted]

New York West - Amherst

The Amherst Study Area encompasses all or parts of the towns of Amherst, Pendleton, Wheatfield, Wilson, and Lewiston. It is located in Western NY, east of Tonawanda and Niagara, and north of the city of Buffalo. The Erie Canal divides the study area and may present challenges in creating feeder ties and supply expansion (Figure II-26).

Figure II-26

[redacted]

Distribution load in Amherst is primarily served at 13.2 kV and 4.16 kV, with [redacted] Station 138 supplying two 4.8 kV distribution feeders. The area substations are supplied by the 115 kV transmission system, with the exception of a few substations supplied by the 34.5 kV sub-transmission system. Buffalo Station 58 and Buffalo Station 124 are served from the 34.5 kV sub-transmission lines originating out of [redacted] and Buffalo Station 67 is served from 34.5 kV sub-transmission lines originating out of [redacted] substation.

Table II-120
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
96	13	58,857	295 MW

Table II-121
Major Electrical Facilities (Substation)

Substations			
Buffalo Station 058	Buffalo Station 124	Buffalo Station 054	Buffalo Station 138
Maple Road 140	Niagara Falls Blvd 130	Oakwood Station 232	Shawnee Road 76
Sweethome Road 224	Buffalo Station 067	Getzville Station 060	Tonawanda Creek Road 06
Ayer Road 211	Youngman Terminal Station		

Table II-122
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Youngman Terminal Station	Buffalo Station 124	605
Youngman Terminal Station	Buffalo Station 058	605
Youngman Terminal Station	Buffalo Station 124	606
Youngman Terminal Station	Buffalo Station 058	606

Issues Identified (2009 – 2015)

Based on 2008 actual loads, eleven distribution feeders are projected to exceed summer normal rating by 2015. In addition, a number of supply transformers are projected to exceed summer emergency ratings in the event of a contingency (Tables II-123 and 124).

Table II-123
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
4	11	0	0	0	0

Table II-124
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	10	3	6	0	0

Recommended Improvements

It has been recommended that [redacted] substation 115/13.2 kV and four new feeders be installed adjacent to [redacted] Station to address transformer contingency MWh exposure and feeder overloads. In addition, switching projects have been recommended to relieve the area.

Table II-125
Project Level Detail

Need Year	Summary Level Scope
2008	[redacted] - Installation of a 115/13.2 kV substation and (4) distribution feeders
2011	[redacted] Feeder [redacted] - Install (2) 900 kVAR capacitors to reduce loading

New York Central - North Cattaraugus

The North Cattaraugus study area has approximately 14,700 customers and a forecasted 2009 summer peak load of 30.3 MW.

Figure II-27

[redacted]

Table II-126
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
27	17	14,740	30.3 MW

Area customers are supplied by seven 13 kV feeders, five of which are fed via 2-115/13 kV transformers at the Valley #44 substation. The remaining 2-13 kV feeders are fed off 34.5/13.2 kV transformers at the [redacted] substations. There are also twenty 4 kV feeders, all supplied by 34.5/4.8 kV transformers at various area substations. There are seven 34.5 kV sub-transmission lines that provide supply for the 34.5/4.8 kV transformers with minimal customers fed off the 34.5 kV system.

Table II-127
Major Electrical Facilities (Substation)

Substations			
Cattaraugus #15	Delavan #11	East Otto #28	Farmersville #27
Franklinville #24	Machias #13	North Ashford #36	Valley #44
West Salamanca #16	West Valley #25	Price Corners #14	Reservoir #103
South Randolph #32	Steamburg #17		

Table II-128
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Delavan #11	Machias #13	801
Machias #13	Maplehurst #4	802
Dake Hill	Machias #13	803
Cold Spring	West Salamanca #16	804
Bagdad	Dake Hill	815
Dake Hill	W. Salamanca #16	816
North Ashford #36	Nuclear Fuels	817

Issues Identified (2009 – 2015)

The 2009 Annual Plan results for this area show one transformer normal loading concern (at [redacted] substation) through 2015.

Table II-129
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	1	1	0	0

Table II-130
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The proposed solution for the issue previously discussed is to replace the existing transformer with a larger unit.

Table II-131
Project Level Detail

Need Year	Summary Level Scope
2009	Replace the existing 34.5/4 kV [redacted] transformer with a larger unit.

New York West – North Chautauqua

The North Chautauqua study area has approximately 26,100 customers and a forecasted 2009 summer peak load of 91 MW.

Figure II-28
Area Map

[redacted]

Table II-132
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
30	20	26,127	91 MW

Customers in this area are supplied by ten 4.8 kV feeders, which are all fed from 34.5/4.8 kV transformers. There are also twenty 13.2 kV distribution feeders, with all but one fed by 115/13.2 kV transformers at various substations in the area. One 13.2 kV feeder is supplied by a 34.5/13.2 kV transformer at the [redacted] substation. There are eight 34.5 kV sub-transmission lines which provide the supply to the 34.5/4.8 kV stepdown transformers.

Table II-133
Major Electrical Facilities (Substation)

Substations			
Bemus Point #159	Bennett Road #99	Berry Road #153	Brigham Road #64
Cassadaga #61	Dunkirk	E. Dunkirk #63	Ellicott #65
Greenhurst #60	Hartfield #79	North Angola	Oakhill #62
Roberts Road #154	Sinclairville #72	West Portland #151	

Table II-134
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Dunkirk	West Portland	851
Dunkirk	Hartfield	852
Shaleton	North Angola	856
North Angola	Bagdad	857
Hartfield	South Dow	859
North Angola	North Ashford	861
North Angola	Bagdad	862
West Portland	Hartfield	866

Issues Identified (2009 – 2015)

The 2009 Annual Plan analysis shows there to be two distribution feeders ([redacted] and [redacted] and two transformer ([redacted]) with summer normal loading issues through 2015. Resolution will be achieved by replacing the equipment that is limiting capacity. Two transformers were initially identified as having outage exposure concerns, due to the amount of load fed from a single 115/13.2 kV transformer. Subsequent detailed analysis shows there to be sufficient feeder tie capability to keep the exposure at acceptable levels.

Table II-135
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
2	2	1	2	0	0

Table II-136
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	2	2	0	0

Recommended Improvements

Installation of distribution line and substation capacitors on the [redacted] substations have been recommended as the solution to voltage performance concerns that could result from area transmission line contingencies.

Table II-137
Project Level Detail

Need Year	Summary Level Scope
2009	Install D line and substation capacitors to address transmission contingency voltage issues.
2009	Replace the existing regulators at [redacted] with 2-250 MVA, 520 amp units.
2009	Replace the existing [redacted] transformer with a 3.75/4.687 MVA unit.

New York West – Chatauqua South

The Chatauqua South area is in the southwest part of New York and has four 13.2kV feeders and twenty 4.8kv delta feeders. It includes the towns of Clymer, Busti, Sherman, Harmony, Poland, Carroll, Mina, and Ripley.

Figure II-29

[redacted]

Table II-138
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
24	14	17,033	51 MW

The Baker Street substation is supplied at 115kV, while all other area substations are supplied by the 34kV sub-transmission system.

There are five 34 kV lines that are supplied from Hartsfield and South Dow 115kV lines.

Table II-139
Major Electrical Facilities (Substation)

Substations			
Baker St	French Creek	Busti	Chatauqua
Clymer	Findley Lake	Frewsburg	Levant
North Chatauqua	Panama	Poland	Ripley
Sherman	Stow		

Table II-140

Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
West Portland	Sherman	867
Hartfield	Sherman	855
Sherman	Ashville	863
Hartfield	Ashville	854
South Dow	Poland	865

Issues Identified (2009 – 2015)

Several feeders are limited by fuses which will need to be replaced with loadbreak switches. Proposed capacity upgrades for the area include one transformer replacement and several load transfers which requires the installation of additional disconnect switches.

A winter loading issue was identified at the [redacted] area. The installation of additional capacitor banks was previously requested. As an alternative to upgrading the distribution system, the customer is also considering converting their service to one supplied at a higher voltage. Alternatives for serving Peek n' Peak are still under review and discussion with the customer.

Table II-141
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
3	3	1	3	0	0

Table II-142
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

Projects will be issued to install a 3.6 MVAR station capacitor bank at [redacted] for reactive support as requested by transmission planning to address system voltage performance concerns that could result from certain Transmission line contingency situations. Additional capacitor banks will be installed on the three distribution feeders served from [redacted] substation to fully resolve this Transmission concern.

The Baker Street substation will require further review to quantify the potential load at risk in the event of a supply contingency.

Table II-143
Project Level Detail

Need Year	Summary Level Scope
2010	Replace 65k fuses at front end of [redacted]
2010	NW [redacted] Repl 65K fuse with load break switch
2011	Transfer 20A load from [redacted] to [redacted] Xfrm
2011	NW Install 900 kVar dist cap banks on [redacted] feeders
2011	NW Panama [redacted] feeder Add cap bank
2012	NW Install [redacted] station 3.6 MX cap bank
2012	Upgrade [redacted] xfrm and regulator ratings.
2014	Transfer 400kw load from [redacted] sub

New York West - Cheektowaga

The Cheektowaga area is east of Buffalo. There are several stations in this area that are supplied by 115kV. [redacted] is the largest and has two transformers that serve the 34kV. Dale Rd sub is 115 / 13.2kV supply, while the [redacted] Stations 61 and 154 are 115 / 4.16kV supplies. The balance of the substations in the area are 34/4.16 kV.

Figure II-30

[redacted]

Table II-144
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
17	11	8,015	44 MW

There are three 34kV supply lines that serve several large customers. The largest load is the Galleria Mall complex which includes 14 padmount switchgear fed from the 701 and 703 34kV lines.

Table II-145
Major Electrical Facilities (Substation)

Substations			
Buffalo Sta 61	Buffalo Sta 66	Buffalo Sta 121	Buffalo Sta 132
Buffalo Sta 146	Buffalo Sta 154	Dale Rd 213	Walden 69

Table II-146
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Walden	Amherst	701
Walden	Ledyard Sw Structure	702
Walden	Galleria Mall	703

Issues Identified (2009 – 2015)

Forecasted loading concerns exist at [redacted] which has several feeders with projected overloads.

Table II-147
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
3	5	0	0	0	0

Table II-148
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The installation of several capacitor banks and the installation of feeder ties to allow transfer of load to [redacted] was proposed in the 2008 Annual Capacity Plan and should be complete prior to the end of FY10.

A detailed study of [redacted] is required in order to analyze a transmission request to convert the substation's back-up supply, the 704 line, to 115kV operation. This station serves only about 1 MW load in an industrial park and it may be possible to request nearby NYSEG to serve this load to allow the retirement of the station.

There is new customer load that has been added at [redacted] on the site of the old [redacted] Customer plans on additional loading in two more phases over next 3-5 years. If this new load develops, mainline upgrades and a new feeder installation, [redacted] will be needed and are recommended as future projects.

Table II-149
Project Level Detail

Need Year	Summary Level Scope
2012	NW New [redacted] feeder assoc D Line OH UG work for added service to [redacted]
2013	NW New [redacted] feeder assoc D Line OH UG work for added service to [redacted]

New York West – Elm

The Elm area is located in the City of Buffalo. It is comprised of urban-suburban residential areas with commercial/manufacturing mixed in.

Most of the load is served by 4 kV underground feeders from local substations supplied by 23 kV cables and multiple, paralleled transformers. This system maintains very high service reliability.

The Buffalo secondary network system is supplied by sixteen 23kV feeders from the [redacted] substation. The Buffalo secondary network system supplies 109MVA of load, representing approximately 1100 customers.

Figure II-31
[redacted]

Table II-150
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
17	13	1,722	14.1 MW

Table II-151
Major Electrical Facilities (Substation)

Substations			
Buffalo Station # 49	Buffalo Station # 50	Waterfront Station # 205	

Table II-152
Major Electrical Facilities (Lines)

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Elm Station	Emerg Hosp	1-E
Elm Station	Dunn Tire Park	2-E
Elm Station	---------	3-E
Elm Station	Sta 48	4-E
Elm Station	Sta 38	5-E
Elm Station	Sta 38	6-E
Elm Station	Sta 41	7-E
Elm Station	Sta 41	8-E
Elm Station	Sta 41	9-E
Elm Station	Dunn Tire Park	10-E
Elm Station	Sta 34	16-E
Elm Station	Sta 34	17-E
Elm Station	Sta 34	18-E
Elm Station	Sta 38	23-E
Elm Station	Sta 34	27-E
Elm Station	Sta 41	35-E

Issues Identified (2009 – 2015)

Although growth is forecasted at just 0.8 percent to 1.3 percent through 2015, significant spot load additions are anticipated and have been planned for in the [redacted] Projects required to serve these significant spot load additions have been recommended and are included in this annual plan.

There are no additional thermal issues in this area through 2015. One distribution feeder will reach 100 percent SN rating and two 23 kV supply cables will require upgrade or relief in about 2017-2018.

Table II-153
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Table II-154
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The following project is recommended for this study area.

Table II-155
Project Level Detail

Need Year	Summary Level Scope
2010	Est. 4 new 23kV lines sourced from [redacted] to accommodate area load growth in medical corridor

New York West – Erie South

The Erie South area is just south of the city of Buffalo with about half the feeders operating at 13.2kV. The 115kV system supplies the 13.2kV stations. The remaining feeders operate at 4800 volt delta or 4160 volts. One 34 kV supply line, 860, serves the 4kV area.

Figure II-32

[redacted]

Table II-156
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
42	18	36,804	103 MW

Table II-157
Major Electrical Facilities

Substations			
West Perrysburg	Buffalo Station 139	Collins	Eden Center
Langford	North Collins	Ridge 142	Buffalo Station 55
Cloverbank	Delameter	Harborfront 212	Lakeview Road
North Eden	Slade Ave 207		

Table II-158
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
North Eden	Eden	860

Issues Identified (2009 – 2015)

Several transformers and feeders in the area have load issues because limited feeder ties exist for operating flexibility. A few small fuses which are limiting feeders will need to be replaced with disconnect switches. Some of the stations are equipped with LTC transformers while others have feeder regulators. The delta feeders have two regulators connected delta.

Table II-159
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	3	4	5	0	0

Table II-160
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

Upgrades recommended in this area include:

- Replace / upgrade regulators at [redacted]
- Complete [redacted] substation installation with 20 MVA transformer
- Replace / upgrade [redacted] with 3750 KVA
- Replace / upgrade [redacted] with 5 MVA LTC transformer

Table II-161
Project Level Detail

Need Year	Summary Level Scope
2011	Install LB and transfer 25A load from [redacted]
2011	Install LB and transfer 35A load from [redacted]
2012	NW Add 300 kvar cap bank to [redacted] feeder
2012	Upgrade [redacted] by replacing regulators
2012	NW Add cap banks to [redacted] feeders
2012	Replace xfrm at [redacted] sub.
2013	NW Add 300 kVar cap banks to the [redacted] feeders
2013	Replace [redacted] transformer

New York West – North Genesee

The North Genesee study area has approximately 44,300 customers and a forecasted 2009 summer peak load of 146.5 MW.

There are a total of 51 distribution feeders that supply customers in this area. There are twenty 13.2 kV feeders, with four being supplied from 34.5/13.2 kV transformers, and the rest are fed from 115/13.2 kV transformers. The 31 4 kV feeders are all fed from 34.5/4.8 kV transformers. There are ten 34.5 kV sub-transmission lines that supply the distribution stepdown transformers.

Figure II-34

[redacted]

Table II-162
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
51	27	44,302	146.5 MW

Table II-163
Major Electrical Facilities

Substations			
Albion #80	Barker #78	Brockport #74	Burt #171
Butts Road #72	Eagle Harbor #92	Gasport #90	Iroquois Rock
Lyndonville #95	Middleport #77	Newfane #170	Royalton #98
South Newfane #71	Shelby #76	Southland Foods #84	Telegraph Road
University #81	Waterport #73	West Albion #79	West Hamlin #82

Table II-164
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Phillips Road	Medina	301
Telegraph Road	Medina	302
Telegraph Road	Medina	303
Phillips Road	Telegraph Road	304
Medina	Albion	305
Waterport	Albion	306
Waterport	Brockport	307
Albion	Brockport	308
Brockport	Owens Illinois	310
Gasport	Telegraph Road	312

Issues Identified (2009 – 2015)

The 2009 Annual Plan identified loading on two distribution feeders ([redacted] and [redacted]) and three transformers ([redacted]) that will exceed summer normal ratings through 2015. Loading on two transformers are forecasted to exceed summer emergency ratings for loss of one unit. Two feeders and one transformer were identified as having contingency outage exposure concerns. No sub-transmission line loading issues were identified.

Solutions are proposed for all of the loading issues and the two feeder outage exposure concerns.

Table II-165
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	2	2	3	0	0

Table II-166
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
2	2	1	1	0	0

Recommended Improvements

One issue in this area is the relatively low capacity of the 34.5/13.2 kV transformers. The largest size used is a 5.25 MVA nameplate unit and has a summer normal and emergency rating of about 5.7 and 6.3 MVA, respectively. The input received for this size is that anything larger would have protection issues. Experience in New England has shown that 7.5/9.375 MVA nameplate units should be used for 23/13 kV modular feeders with capacities of about 11 or 12 MVA. A review of the consequences of protection issues with installing larger units in New York should be investigated. Taking advantage of higher transformer and feeder capacity for 13.2 kV feeders supplied from 34.5/13.2 kV transformers would provide an option for needed load relief.

Table II-167
Project Level Detail

Need Year	Summary Level Scope
2009	Install capacitors on the [redacted] distribution feeders.
2009	Reconductor 500 feet of the [redacted] getaway with 1000 copper conductor.
2009	Install new ducts and 1000 copper cable to reconductor the [redacted] getaway.
2009	Install 3-600 KVAR capacitor banks on the [redacted] distribution feeder.
2009	Extend the [redacted] feeder and transfer 25 amps to it from [redacted]
2009	Install a second 34.5/13.2 kV, 5.25 MVA transformer and 3-333 kVA regulators at [redacted].
2012	Transfer 54 amps from [redacted] to [redacted] feeder.
2013	Transfer 15 amps from the [redacted] feeder.

New York West – Genesee South

The Genesee South study area is defined by the region that includes the city of Batavia and the surrounding towns and villages. It is located in western NY east of Buffalo and Southwest of the city of Rochester.

The primary distribution system voltages in Genesee South are 13.2kV and 4.8kV. Most of the 13.2 kV system is fed from the area 115kV transmission system. The rest of the 13 kV system, as well as the 4kV system, is fed from a 34.5kV sub-transmission system supplied out of the [redacted] substations.

Figure II-35

[redacted]

Table II-168
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
44	25	37,105	141 MVA

Table II-169
Major Electrical Facilities

Substations			
Attica 12	Basom 15	Batavia 1	Byron 18
Corfu 22	Darien 16	E. Batavia 28	Elba 20
Knapp Rd. 226	Lapp 26	Linden 21	Mumford 50
N. Leroy 4	Oakfield 3	Orangeville 19	Sheppard Rd. 29
Caledonia 44	Wethersfield 23	Willow Specialties 24	

Table II-170
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Caledonia	Golah	213
North Leroy	Caledonia	203
Attica	Wethersfield	209
North Leroy	Attica	208
Batavia	Attica	206
North Akron	Attica	225
Batavia	North Leroy	223
Oakfield	Batavia	219
Oakfield	Caledonia	201
North Akron	Oakfield	227
I2R Element	North Akron	204
I2R Element	North Akron	205

Issues Identified (2009 – 2015)

Normal feeder overloads in this area are seen on [redacted], [redacted] and [redacted] (130 percent and 112 percent respectively in 2009) and [redacted] (100 percent in 2013). These overloads can be relieved by reconductoring getaways at each substation. There are also two transformers projected to have normal overloads; [redacted] (120 percent and 161 percent respectively in 2009). These two overloads can be relieved by the addition of second transformers at each station.

Contingency outage exposure concerns occur for the loss of the [redacted] single transformer and the [redacted] single transformer. In 2015 these two stations would have 295 and 310 MWHrs of unserved load respectively. Operating flexibility to respond to contingencies can be improved with the construction of additional area feeder ties.

Finally transmission had requested a study of added VAR support on the distribution system. Additional VARS are being added through the use of distribution line capacitor banks as part of this annual plan.

Table II-171
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
2	2	2	2	0	0

Table II-172
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	2	2	0	0

Recommended Improvements

After the proposed work in this area is complete, there will be no further design criteria violations in the five year planning horizon.

Table II-173
Project Level Detail

Need Year	Summary Level Scope
2008	Reconductor [redacted] - [redacted] Substation
2008	[redacted]- Add a second transformer bank.
2009	Install distribution line capacitors on [redacted]substation feeders
2009	Install distribution line capacitors on [redacted]substation feeders
2009	Install distribution line capacitors on [redacted] substation feeders
2009	Add feeder tie - [redacted]
2009	[redacted] - Upgrade Transformer
2010	Add feeder tie - [redacted]
2013	[redacted] Upgrade Getaways

New York West – Grand Island

The Grand Island area is on Grand Island between Buffalo and Niagara Falls. This suburban-rural area is primarily residential with areas of commercial and a few industrial parks. There are two National Grid substations supplied from 115 kV with distribution feeders at 13.2 kV.

Growth is forecasted at 0.8 percent to 1.3 percent through 2015

Figure II-36

[redacted]

Table II-174
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
9	3	8,017	41.8 MW

Table II-175
Major Electrical Facilities

Substations			
Grand Island # 64	Long Road # 209		

Table II-176
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
None		

Issues Identified (2009 – 2015)

One feeder normal overload and one transformer contingency overload was forecasted through 2015. To address these issues a new feeder at [redacted] substation, re-rating the underground getaway at [redacted] substation is proposed. Beyond the current study horizon, one additional feeder will require relief in 2016. Proposals to address this issue will be made in the 2010 Capacity Plan review. No other issues are evident through 2020.

Table II-177
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	0	0	0	0

Table II-178
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

There are no improvements recommended for this area at this time.

New York West – Kensington

The Kensington study area has approximately 37,100 customers and a forecasted 2009 summer peak load of 91.7 MW.

There are eighty 4 kV feeders, supplied from thirty eight 23/4.8 kV transformers and nineteen 23 kV sub-transmission lines in this area. The Kensington substation has four 115/23 kV transformers, and provides the supply to the area's 23 kV sub-transmission system. This substation is located in Buffalo and the study area is exclusively underground distribution.

Figure II-37

[redacted]

Table II-179
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
80	38	37,145	91.7 MW

Table II-180
Major Electrical Facilities

Substations			
Buffalo Station #21	Buffalo Station #27	Buffalo Station #28	Buffalo Station #30
Buffalo Station #31	Buffalo Station #32	Buffalo Station #53	Buffalo Station #68
Buffalo Station #157	Buffalo Station #162	Kensington #158	

Table II-181
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Kensington	Buffalo Station #68	1K
Kensington	Buffalo Station #68	2K
Kensington	Buffalo Station #68	3K
Kensington	Buffalo Station #68	4K
Kensington	SUNY Buffalo	5K
Kensington	SUNY Buffalo	6K
Kensington	Clearing Niagara	7K
Kensington	Meyer Memorial Hospital	8K
Kensington	Buffalo Station #157	9K
Kensington	Buffalo Station #26	10K
Kensington	Buffalo Station #26	11K
Kensington	Buffalo Station #26	12K
Kensington	Buffalo Station #28	13K
Kensington	Buffalo Station #26	14K
Kensington	Buffalo Station #26	15K
Kensington	Buffalo Station #22	21K
Kensington	Buffalo Station #22	22K
Kensington	Buffalo Station #22	23K
Kensington	Buffalo Station #22	33K

Issues Identified (2009 – 2015)

The 2009 Annual Plan has identified loading on two distribution feeders and four transformers at the [redacted] station exceeding summer normal ratings through 2015. The same four transformers have loading above their summer emergency ratings for the loss of one unit. No supply line loading or contingency outage exposure concerns were noted.

Table II-182
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	2	0	4	0	0

Table II-183
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The [redacted] station is scheduled to be rebuilt by 2013 through an existing asset replacement program, with new transformers and all 4 kV feeder getaways reconductored. This will resolve all loading issues.

Table II-184
Project Level Detail

Need Year	Summary Level Scope
2009	Transfer the [redacted] feeder (86 amps) to the [redacted] feeder.
2009	Transfer 39 amps from the Buffalo Jewett [redacted] to the [redacted] feeder.

New York West – Livingston

The Livingston study area is made up of Livingston county in western New York. It is located in western New York south of Rochester and east of Buffalo.

The primary distribution system voltages in Livingston are 13.2kV and 4.8kV. Most of the area is fed from a 34.5kV sub-transmission system supplied out of the [redacted] substations. There is also one 13kV station fed directly from the 115kV and some 69kV sub-transmission lines in the area.

Figure II-38

[redacted]

Table II-185
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
30	18	21,713	69 MVA

Table II-186
Major Electrical Facilities

Substations			
Avon 43	Conesus 52	E. Golah 51	Geneso 55
Groveland 41	Hemlock 38	Industry 47	Lakeville 40
Lima 36	Livingston 130	Livonia 37	Richmond 32
York Center 53			

Table II-187
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
N. Lakeville	Ridge	218
N. Lakeville	Hemlock	224
N. Lakeville	Richmond	226
Golah	N. Lakeville	217
Golah	N. Lakeville	216
Mortimer	Golah	109
Golah	S. Perry	853

Issues Identified (2009 – 2015)

One normal feeder overload is forecasted in the area from the [redacted] substation. Significant feeder rearrangements in the area are planned as part of the installation of the second transformer at [redacted] substation. Loading at [redacted] will be monitored following these load transfers and any additional upgrades that may be necessary will be identified in the next annual plan review.

Table II-188
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	1	0	0

Table II-189
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	0	0	0	0

Recommended Improvements

After the proposed work in this area is complete, there will be one feeder that will continue to have significant contingency outage exposure for the loss of [redacted] (18MWHrs in 2015) that will not be resolved in this 5 year planning horizon.

Future capacity reviews will monitor the loading in the area of the Conesus, Geneseo, Lakeville and Livonia substations. Additional capacity could be added to this area with the installation of a new S. Livingston 115/13.2 kV substation. Although this project cannot be justified presently, it may be re-submitted at a future date.

Table II-190
Project Level Detail

Need Year	Summary Level Scope
2008	Add a second transformer at [redacted]
2008	Add two secondary breakers for new [redacted] feeders and rework substation feeders

New York West – Niagara

The Niagara Study Area is in Western NY and encompasses the towns of Lewiston, Porter and Wilson. Niagara is bordered to the west by the Niagara River, to the North by Lake Ontario, and to the south by the Power Reservoir.

Figure II-39
Area Map

[redacted]

Area distribution is served primarily at 4.8 kV and supplied by a 34.5 kV sub-transmission loop configuration. Swann Road substation serves distribution load at 13.2 kV and is supplied by the 115 kV transmission system.

Table II-191
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
15	6	12,443	35 MW

Table II-192
Major Electrical Facilities

Substations			
Lewiston Heights 86	Ransomville 89	Youngstown 88	Swann Road 105
Wilson 93	Lewiston 87		

Table II-193
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Youngstown 88	Lewiston 87	401
Ransomville 89	Phillips Rd	402
Youngstown 88	Sanborn	403
Mountain	Sanborn	404
Lewiston Heights 86	Mountain	405

Issues Identified (2009 – 2015)

Loading on the [redacted] and [redacted] substations currently exceeds summer normal ratings during peak load periods.

Table II-194
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	2	2	0	0

Table II-195
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

There are project recommendations to relieve these substations through transformer bank replacement.

Table II-196
Project Level Detail

Need Year	Summary Level Scope
2008	Conversion, Line Installation, and Reactive Support to relieve [redacted] and [redacted] Stations
2008	Replace existing 3.0MVA transformer at [redacted] substation with a 5.3MVA transformer
2013	[redacted] - Install 300 kVAR capacitor bank to provide reactive support and load relief

New York West – Niagara Falls

The Niagara Falls Study Area is in Western NY and is bordered to the north, south, and west by the Niagara River. The Power Reservoir also borders the area to the north, east of the Niagara River. Interstate 190 runs from the north to the south along the western section of the area. The Amtrak rail runs from the east to the west along the northern section of the area. The Niagara Falls International Airport lies west of the city. These boundaries limit feeder tie and distribution supply expansion in the area.

Figure II-40

[redacted]

The Niagara Falls secondary network system is supplied by three 12kV feeders from the Gibson substation. The Niagara Falls secondary network system supplies 1MVA of load, representing approximately 20 customers.

The area is supplied by the 115 kV transmission system and the 12 kV sub-transmission system supplied by Harper and Gibson substations. Distribution load is served by 13.2 kV, 4.8 kV, and 4.16 kV circuits.

Table II-197
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
67	29	38,657	153 MW

Table II-198
Major Electrical Facilities

Substations			
Eighth Street 80	Eleventh Street 82	Lockport Road 216	Military Road 210
Milpine 96	Stephenson Ave. 85	Summit Park 97	Walmore Road 217
Welch Ave. 83	Beech Street 81	Buffalo Ave. 215	Gibson
Harper			

Table II-199
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Harper	Welch Ave. 83	52
Harper	Welch Ave. 83	53
Harper	Welch Ave. 83	54
Harper	Welch Ave. 83	55
Harper	Eighth Street 80	60
Harper	Eighth Street 80	61
Harper	Welch Ave. 83	62
Harper	Welch Ave. 83	63
Harper	Eighth Street 80	65
Harper	Stephenson Ave. 85	653
Harper	Stephenson Ave. 85	654
Harper	Stephenson Ave. 85	655
Gibson	Titanium	71
Gibson	Globar	73

Issues Identified (2009 - 2015)

Eight feeders are projected to exceed summer normal rating by 2015.

Table II-200
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
5	8	3	3	0	0

Table II-201
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		**Transformers**		**Supply Lines**	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	3	0	0	0	0

Recommended Improvements

Load relief switching projects have been recommended to relieve all current issues in this area.

Table II-202
Project Level Detail

Need Year	**Summary Level Scope**
2010	[redacted] Feeder [redacted] - Install a 900 kVAR capacitor bank to improve loading and voltage profile
2011	Transfer 49A by switching from feeder [redacted] onto feeder [redacted]
2012	Install a 3-300 KVAR capacitor bank on feeder [redacted] to improve loading and voltage profile
2013	Transfer approximately 37A from [redacted] to [redacted] and improve loading and voltage profile

New York West – Olean

The Olean study area has approximately 18,700 customers and a forecasted 2009 summer peak load of 61 MW.

Figure II-41

[redacted]

There are twenty total distribution feeders that provide service to area customers. There are eight 4 kV feeders supplied by 34.5/4 kV transformers at various stations. Eleven of the area's twelve 13.2 kV feeders are fed off 115/13.2 kV transformers. The remaining single feeder is served from a 34.5/13.2 kV transformer at the [redacted] substation. There are three 34.5 kV sub-transmission lines.

Table II-203
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
20	12	18,679	61 MW

Table II-204
Major Electrical Facilities

Substations			
Dugan Road #22	Maplehurst #4	North Olean #30	Vandalia #104
Niles	Homer Hill	West Olean #33	Cuba #5
Cuba Lake #37			

Table II-205
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
West Salamanca	Homer Hill	805
Homer Hill	Ceres	809
Homer Hill	Nile	811

Issues Identified (2009 – 2015)

The 2009 Annual Plan results show there to be no loading or contingency outage exposure concerns in the Olean study area.

Recommended Improvements

There are no improvements recommended for this area at this time.

New York West – Sawyer

The Sawyer area is part of the City of Buffalo. It is mixed urban-suburban residential with commercial/manufacturing mixed in.

Most of the load is served by underground 4 kV cables served from local substations supplied by 23 kV cables and multiple, paralleled transformers. This system maintains very high reliability.

Growth is forecasted at 0.8 percent to 1.3 percent through 2015.

Figure II-42

[redacted]

Table II-206
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
163	68	62,489	156.2 MW

Table II-207
Major Electrical Facilities

Substations			
Buffalo Station 022	Buffalo Station 023	Buffalo Station 024	Buffalo Station 025
Buffalo Station 026	Buffalo Station 029	Buffalo Station 033	Buffalo Station 037
Buffalo Station 045	Buffalo Station 047	Buffalo Station 048	Buffalo Station 052
Buffalo Station 056	Buffalo Station 126	Buffalo Station 160	Buffalo Station 161
Buffalo Station 201	Buffalo Station 202	Buffalo Station 203	Buffalo Station 204
Buffalo Station 208			

Table II-208
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Sawyer	Buffalo Station 22	1-H
Sawyer	Buffalo Station 22	2-H
Sawyer	Buffalo Station 22	3-H
Sawyer	Buffalo Station 22	1-H
Sawyer	Buffalo Station 22	2-H
Sawyer	Buffalo Station 22	3-H
Sawyer	Buffalo Station 201	4-H
Sawyer	Buffalo Station 201	5-H
Sawyer	Buffalo Station 37	6-H
Sawyer	Buffalo Station 48A	7-H
Sawyer	Buffalo Station 48A	8-H
Sawyer	Buffalo Station 33	9-H
Sawyer	Buffalo Station 26	10-H
Sawyer	Buffalo Station 26	11-H
Sawyer	Buffalo Station 26	11-H
Sawyer	Buffalo Station 26	12-H
Sawyer	Buffalo Station 22	13-H
Sawyer	Buffalo Station 22	13-H
Sawyer	Buffalo Station 26	14-H
Sawyer	Buffalo Station 26	15-H
Sawyer	Buffalo Station 160	16-H
Sawyer	Buffalo Station 160	17-H
Sawyer	Buffalo Station 160	18-H
Sawyer	Buffalo Station 37	19-H
Sawyer	Buffalo Station 33	20-H
Sawyer	TOPS	21-H
Sawyer	Buffalo Station 48A	22-H
Sawyer	Buffalo Station 56	26-H
Buffalo Station 56	Kenmore Mercy Hospital	26-H
Sawyer	Buffalo Station 161	27-H
Sawyer	Buffalo Station 56	28-H
Buffalo Station 56	Kenmore Mercy Hospital	28-H
Sawyer	Buffalo Station 48	29-H
Sawyer	Buffalo Station 126	33-H
Sawyer	Buffalo Station 126	34-H
Sawyer	Buffalo Station 33	35-H
Buffalo Station 33	Buffalo Station 204	35-H
Sawyer	Switch 578	36-H

Issues Identified (2009 – 2015)

There are projected overloads on 11 feeders, 4 transformers, and 5 supply circuits by 2015. There are projected contingency overloads on 5 transformers and 5 supply circuits by 2015. All concerns are addressed by load transfers and infrastructure development projects identified in this annual plan review.

Table II-209
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
4	11	4	4	5	5

Table II-210
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

Issues in this area will be corrected via load transfers requiring only small amounts of distribution line work to create new feeder ties. Five supply cables from [redacted] require upgrade to larger cable.

Looking beyond the current study horizon, six feeders and nine transformers will require relief between 2016 and 2018. Five supply cables have remaining contingency overloads which do not pose a significant contingency exposure but may require operations to respond to in a timely fashion if a contingency were to occur at peak load periods.

Table II-211
Project Level Detail

Need Year	Summary Level Scope
2009	Contingency relief for [redacted] supply cable
2009	Load relief for [redacted] via new switch
2009	Reconductor supply cable [redacted]
2010	Relieve [redacted] xfer load to [redacted]
2010	[redacted] Feeder Relief - Install 3 100 KVAR fixed capacitor bank
2010	Relieve [redacted] via switching to [redacted]
2013	Relieve [redacted] via xfr to [redacted]
2014	Create new tie between [redacted] and [redacted] at the corner of [redacted] and [redacted] XFR load
2015	Recond [redacted] to 350 CU
2015	Relieve [redacted] xfr to [redacted]

New York West – Seneca

The Seneca area is located in the southeast section of Buffalo. It is served primarily from the Seneca Station which contains four 230 / 23kV transformers and serves 25 supply lines at 23kV.

Figure II-43

[redacted]

Table II-212
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
133	55	48,433	125 MW

The majority of the distribution stations in this area are served by four supply cables and have four 23 / 4.16 kV transformers. As with all of the city of Buffalo, all distribution load is served at 4.16kV. Several large customers are served directly from the 23kV system including OLV Hospital, Buffalo Color, Scrap Property Associates, Mercy Hospital, Sorrento Cheese, Buffalo China, and Industrial Commerce.

The Buffalo-Broadway secondary network system is supplied by four 23kV feeders from the [redacted] substation. The Buffalo-Broadway secondary network system supplies 1MVA of load, approximately 50 customers.

Buffalo station 155 is the only 115 / 4.16kV station with one 9.5 MVA transformer.

Table II-213
Major Electrical Facilities

Substations			
Buffalo Station 34	Buffalo Station 35	Buffalo Station 36	Buffalo Station 38
Buffalo Station 39	Buffalo Station 40	Buffalo Station 41	Buffalo Station 42
Buffalo Station 43	Buffalo Station 44	Buffalo Station 46	Buffalo Station 51
Buffalo Station 59	Buffalo Station 155	Seneca	

Table II-214
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Seneca	Station 46	1-S
Seneca	Station 46	2-S
Seneca	Station 46	3-S
Seneca	OLV Hospital	19-S
Seneca	Station 46	31-S
Seneca	Station 48	4-S
Seneca	Station 48	5-S
Seneca	Station 38	6-S
Seneca	Station 38	23-S
Seneca	Station 42	7-S
Seneca	Station 42	8-S
Seneca	Station 42	9-S
Seneca	Buffalo Color	13-S
Seneca	Buffalo Color	14-S
Seneca	Station 41	30-S
Seneca	Scrap Property	32-S
Seneca	Scrap Property	33-S
Kensington	Seneca	10-S
Kensington	Seneca	11-S
Kensington	Seneca	12-S
Kensington	Seneca	15-S
Seneca	Station 34	16-S
Seneca	Station 34	17-S
Seneca	Station 34	18-S
Seneca	Station 34	27-S

Issues Identified (2009 – 2015)

The substations in this area are designed to be redundant and there are no N-1 contingency exposure concerns. Loss of any supply cable will typically drop one transformer at 3-4 different stations.

All of the distribution 23/4 kV transformers are typically connected in parallel with load tap changers controlled by an LTC paralleling scheme. On occasion issues have been encountered when 4kV feeders have been tied in the field and therefore, these paralleling schemes need to be reviewed.

Table II-215
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
7	11	8	8	0	0

Table II-216
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

There is an ongoing project to replace and upgrade the 23kV cables heading toward the South Park area including 1S, 2S, 3S, 19S, 31S. There is also the need to finish a project to replace three reactors at Seneca Terminal.

Loading issues in this area will be addressed by several projects to install six loadbreak or underground switches and associated load transfers. Some of these projects will include the addition of underground cable.

Ongoing prior work continues on the Station 43 substation rebuild along with the installation of new 500 kcmil copper underground getaway cables for feeders.

Table II-217
Project Level Detail

Need Year	Summary Level Scope
2010	NW Feeder [redacted] Transfer load on Onodaga St to [redacted]
2010	NW Feeder [redacted] Replace UG getaway cable with 500 copper, Rerate
2010	NW [redacted] Extend 4/0 cu underground on Williams st, add d/s, xfer load to [redacted]
2011	NW Feeder [redacted] Inst LB, Xfer load to [redacted]
2011	NW Feeder [redacted] Inst LB switch So.Ogden, Xfer load to [redacted]
2011	NW Replace [redacted] underground getaway cable with 500 Copper, Rerate
2011	NW [redacted] Inst ug switch, Xfer load to [redacted]
2012	NW [redacted] feeder, Install 4/0 cable, tie LB, and Xfer load to [redacted]
2014	NW Buffalo [redacted] feeder, Install LB switch, Xfer load to [redacted]

New York West – Tonawanda

The Tonawanda Study Area is in Western NY and encompasses the towns of North Tonawanda and Tonawanda. Bordering the western section of the area is the Niagara River. Ellicott Creek flows parallel to Tonawanda Creek in the northern part of the town, with a confluence just east of the Niagara River. The eastern section of the area is the Town of Amherst and forming the southern border is the Village of Kenmore and the City of Buffalo.

The area is served primarily by the 115kV transmission system and the 23 kV sub-transmission system. Distribution voltage is served primarily by 4.16 kV circuits, with the exception of one 13.2 kV feeder supplied by the [redacted]ine.

Figure II-44

[redacted]

Table II-218
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
62	10	41,315	87.4 MW

Table II-219
Major Electrical Facilities

Substations			
Buffalo Station 057	Buffalo Station 063	Buffalo Station 074	Buffalo Station 077
Buffalo Station 078	Buffalo Station 079	Buffalo Station 122	Buffalo Station 127
Buffalo Station 129	Buffalo Station 214		

Table II-220
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
Buffalo Station 078	Buffalo Station 077	601
Buffalo Station 077	Buffalo Station 074	601
Buffalo Station 074	Buffalo Station 057	601
Buffalo Station 057	Buffalo Station 127	601
Buffalo Station 127	Buffalo Station 063	601
Buffalo Station 078	Buffalo Station 077	602
Buffalo Station 077	Buffalo Station 074	602
Buffalo Station 074	Buffalo Station 057	602
Buffalo Station 057	Buffalo Station 127	602
Buffalo Station 127	Buffalo Station 063	602
Buffalo Station 078	Buffalo Station 077	603
Buffalo Station 077	Buffalo Station 074	603
Buffalo Station 074	Buffalo Station 057	603
Buffalo Station 057	Buffalo Station 127	603
Buffalo Station 127	Buffalo Station 063	603
Buffalo Station 078	Buffalo Station 077	604
Buffalo Station 078	Buffalo Station 079	622
Buffalo Station 079	Buffalo Station 122	622
Buffalo Station 078	Buffalo Station 079	623
Buffalo Station 078	Buffalo Station 079	624

Issues Identified (2009 – 2015)

A number of feeders are projected to exceed summer normal rating before 2015. Projects to reconductor distribution feeder getaway cables and load relief switching projects have been recommended to relieve these concerns. [redacted] are projected to be overloaded during normal operation as well as potential contingency exposure during emergency operation.

Table II-221
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
5	15	0	3	2	2

Table II-222
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

Installing a new 115/4.16 KV transformer bank at [redacted] is recommended to address thermal concerns with the existing facilities in the Tonawanda area.

Table II-223
Project Level Detail

Need Year	Summary Level Scope
2008	Rebuild and convert feeder [redacted] to relieve feeder [redacted]
2008	[redacted] - Install a second 9.375 MVA 115/4.16 kV transformer
2010	[redacted] - Reconductor Getaway Cables
2010	Rephase single phase tap on feeder [redacted] to reduce loading and improve voltage profile.
2010	Replace [redacted] with 5.25MVA LTC Transformer
2010	To relieve feeder [redacted] we will extend feeder [redacted] and create tie on River Rd

New York West – Wellsville

The Wellsville area is supplied by 115 / 34kV stations at Andover and Nile. There are two 34kV supply lines. This is a small rural area located near the Pennsylvania border.

Load is served by five substations serving the nine 4kV feeders. There is one large customer on the 34kV system called Air Preheater Corp. Another customer is the Andover Village load near Andover sub.

Figure II-45
Area Map

[redacted]

Table II-224
Area Summary

Distribution Feeders	Supply Transformers	Customers	Load
9	5	4,387	9 MW

Table II-225
Major Electrical Facilities

Substations			
Andover	Knights Creek	Petrolia	South Wellsville
Whitesville			

Table II-226
Major Electrical Facilities

Sub-Transmission Supply Lines		
From	To	Supply Line Number
South Wellsville	Andover	541
Nile	South Wellsville	812

Issues Identified (2009 – 2015)

One transformer at [redacted] is projected to be above normal and will require a load transfer to relieve.

Table II-227
Projected to Exceed Summer Normal Thermal Ratings

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
1	1	2	2	0	0

Table II-228
Projected to Exceed Outage Exposure Guidelines

Distribution Feeders		Transformers		Supply Lines	
Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015	Projected Summer 2009	Projected Summer 2015
0	0	0	0	0	0

Recommended Improvements

The following improvement is recommended for the area.

Table II-229
Project Level Detail

Need Year	Summary Level Scope
2011	[redacted]oad transfer to [redacted]

III. ASSET CONDITION

This chapter provides a condition report of National Grid's Transmission, Sub-transmission and Distribution assets. Specifically, the report describes detailed physical condition information where it is available, information on the age profile of the assets and an explanation of how the information is used to identify high risk facilities that may require replacement. Where programs have been developed to address specific problem areas, a description of remedial actions is provided at the end of each system's asset class section. Remedial programs, strategies and other actions will be further described in the T&D Capital Investment Plan to be submitted in January 2010.

As reflected in last year's condition report, the physical elements of National Grid's T&D facilities are in a condition commensurate with their age. Some elements of the T&D network were installed 50 to 70 years ago and certain classes of assets are approaching the end of their useful asset life.[4] While it is not necessarily the case that every transmission or distribution asset should be replaced at the end of its projected service life, the relative age of National Grid's T&D facilities increases the risk that one of those elements will fail under conditions of stress. Thus, while National Grid will not replace T&D assets based solely on age, it indicates the need for further engineering analysis of critical T&D system elements and, in planning, age is a factor that can help predict the volume of assets that will require replacement.

A. Transmission System

This section provides a detailed condition report of the Company's transmission assets in the New York service territory. For the purpose of condition assessment and asset replacement modeling, Table III-1 provides an inventory of key system elements from 2008 to present.

[4] End of useful life - This state is the point at which it is expected that equipment condition will have an unacceptable impact on performance or capability, and repair is either not possible or uneconomic. This state is defined differently for each equipment type as it is a function of the deterioration modes; safety, environmental and operational consequences of failure and the required operational duty and consequent stresses.

Table III-1
Transmission Asset Types (115 kV and above)

Main Asset	Inventory 2008	Inventory 2009
Steel Structures (Towers and Poles)	20,325	20,325
Wood Poles	35,703	35,703
Phase Conductor	18,687 miles	18,687 miles
Cables	51.8 miles	51.8 miles
Substations[5]	295	313
Oil Circuit Breakers[6]	398	377
SF6 Circuit Breakers	292	330
Other circuit breakers	11	1
Transformers[7]	520	508
Batteries[8]	354	260
Chargers	Not reported	349
Surge Arresters[9]	700	691
Sensing Devices	Not reported	835
Reactors	Not reported	9
Disconnects	Not reported	2,442
Relays[10]	6,000	7,966

Areas of Interest

Some specific areas of interest are discussed below. Further details are provided in the respective subsections.

Structures

- 386 steel structures are graded at a level that requires short term asset replacement (Table III-11).
- There are currently 228 reject wood poles that require replacement (Table III-21).
- The overhead line refurbishment (SG080) and wood pole management (SG009) strategies will address these issues

[5] In July 2008, the Company revised its definition of a substation to include motorized switches. This change has increased the count of substations.
[6] As the Company continues to improve the quality of the data in its asset management database year-on-year changes to asset inventory details will naturally occur.
[7] See the above footnote.
[8] Last year the Company reported 354 batteries and chargers combined. This year, the Company chose to separate batteries and chargers and identify that in some instances there are duplicate chargers.
[9] The figure 700 was simply rounded up from the 691 value contained within the Asset Information Maintenance Management System (AIMMS).
[10] This year the Company presents the full inventory including first generation electronic relays and modern microprocessor relays.

Phase Conductors

- Conductor, static wire and splice issues and failures pose significant safety, as well as reliability risk. The conductor clearance (SG029) and the static wire (SG073) strategies address critical issues specific to this area. The overhead line refurbishment strategy (SG080) provides a systematic long-term approach that will address issues related to aging conductors, shield wires and splices.

Substations

- A few transmission substations have significant issues including obsolete design, obsolete equipment, reliability concerns, and other issues. To address these issues, National Grid is developing substation rebuild strategies for sites such as [redacted] and [redacted]

Circuit Breakers

- The upstate New York Transmission system circuit breaker population is mainly (53 percent) made up of older oil circuit breakers and the majority (90 percent) of these are installed at 115kV. The oil circuit breaker population is becoming a maintenance burden and an increasingly aging population puts system reliability and customer service at risk.
- A long-term circuit breaker refurbishment strategy is currently being developed to replace approximately 176 highest priority circuit breakers over the next 10 years (Table III-34)

Transformers

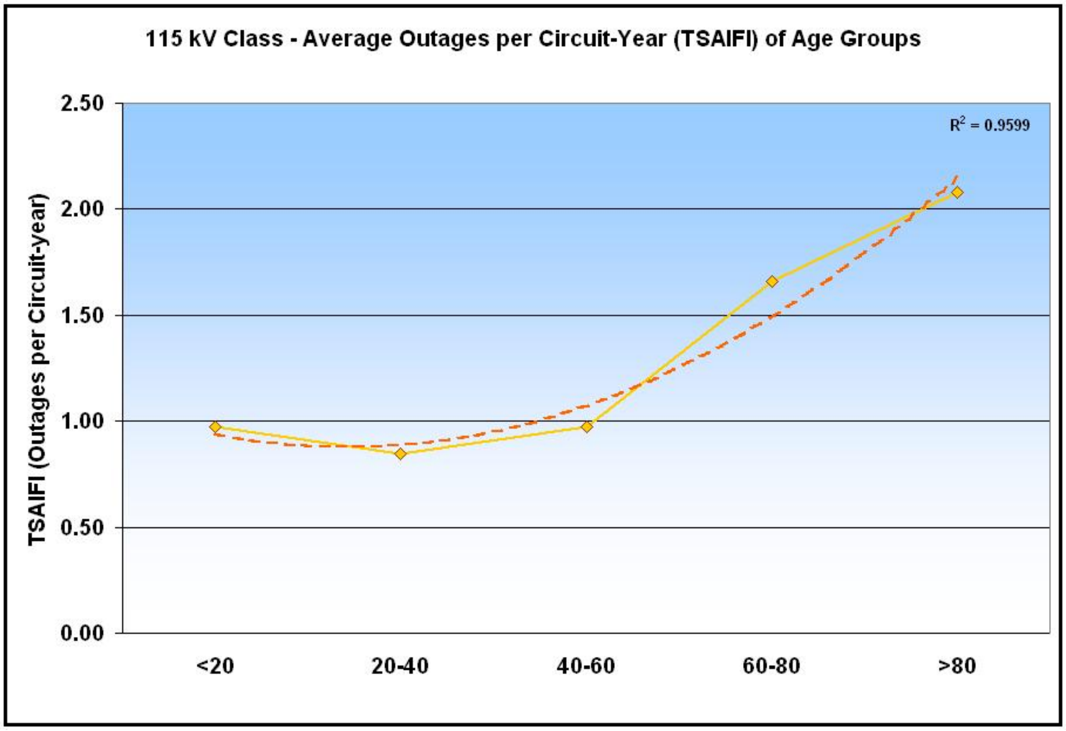
- National Grid has an operational transformer population of 508 units with an average age of 35 years. Nine percent of the transformer fleet is greater than 60 years old with a further 34 percent between 40 and 59 years old.
- We are developing a significant asset replacement program to be implemented within the coming decade to address the 190 highest priority transformers (Table III-38)

Overhead Lines

Age distribution figures for overhead line assets show an aging population of transmission assets in Upstate New York. This is an important point as a recent evaluation of the 115 kV transmission assets demonstrated a strong correlation between age and decreasing reliability (Figure III-1). This chart clearly shows that as 115kV overhead lines age the number of outages increases. It is also important to note that even relatively new circuits will still experience outages.

Unless noted differently, overhead inventory numbers in this section are based upon Transmission Geographic Information System (GIS) extracts taken in 2006. The age profiles presented are based upon more recent information extracted from the Plant Accounting Records.

Figure III-1.
Reliability of 115 kV National Grid US Assets by Age Groups



Condition and Performance Issues

Electric Operating Procedure T007 (EOP T007), "Transmission Line Patrol & Maintenance," outlines the following inspection work is to take place for each transmission line on recurring basis:

- Aerial Visual Patrol: Once each year
- Aerial Infrared Patrol: Once each year
- Ground Based (Foot) Visual Patrol: Once every 5 years
- Wood Pole Inspection and Treatment: Once every 10 years
- Steel Tower Footing Inspection and Repair: Once every 20 years

For the ground based visual patrols, problems found are entered into Computapole via a hand held computer. For the aerial visual and aerial infrared patrols problems found are entered into Computapole manually. Each problem found is given a priority code as follows:

Table III-2.
Priority Codes

Priority Code	Required Response
Level 1	Problem must be repaired/addressed within one week
Level 2	Problem must be repaired/addressed within one year
Level 3	Problem must be repaired/addressed within three years
Level 4	Problem information is used to plan future work but does not need immediate attention.

Table III-3 lists a summary of inspections, problems identified, and number fixed. Problems of concern are fixed in accordance with the priority code.

Table III-3.
Transmission Overhead Inspection Summary

Number of Inspections	Number of Problems	Number of Fixed Problems
9,234	2,704	746

Specifically, the number of Level 2 problems identified and fixes completed is summarized in Table III-4.

Table III-4.
Level 2 Inspection Numbers

Total January 2008 to July 2009	
Identified	**Completed**
71	69
479	455
550	524

Remedial Actions Performed and Planned

To improve reliability over the long term, the Overhead Line Refurbishment Strategy (SG080) was approved in March 2008.[11] This strategy seeks to move US Transmission to a longer, systematic refurbishment approach for addressing overhead lines. This strategy begins a major asset replacement program projected over a 25 year period.

The initial overhead line refurbishment effort will be based primarily upon the list of least reliable transmission lines (five year average). Lines are selected based upon reliability as

[11] Information on this strategy was provided to the NYPSC as Exhibit P-7 of the 2007 Petition Filing

published in the Transmission Network Performance Report[12] (New York lines are selected from the worst 40 load and worst 10 performing bulk lines) and any circuits that may be in the SGS Statistical Services Worst 100 Circuits. The SG080 strategy places an emphasis on the worst performing load circuits in New York. Bundling with other strategies for efficiency reasons, scope, geographic location, outage constraints, licensing, and planning will impact the final construction schedule. For efficiency, both circuits on a double circuit line are refurbished consecutively.

A longer term approach is to prioritize projects by considering condition, line importance, and reliability. This approach is under development and the approach is not expected to change for another two to five years.

The following overhead line refurbishment projects, driven by Strategy SG080, are underway.[13]

Table III-5.
Active SG080 Projects

Project Number	Driver or Strategy	Title[14]	Projected Construction FY
C03389	SG080	[redacted]	FY2011/12
C03417	SG080		FY2011/12
C04718	SG080		FY2009/10
C18670	SG080		FY2009/10

The reliability rankings for the circuits in Table III-5 were as follows:

Table III-6.
Reliability Rankings SG080 Projects Underway

Circuit ID	Circuit Name	2009 Rank	2008 Rank
T1260	[redacted]	2	7
T1270		Double circuit efficiency	
T1530		3	1
T1280		4	3
T1950		Double circuit efficiency	
T1540		18	24
T1550		1	7

12 Published annually by Transmission Operation Planning and Review
13 Excluding lightening enhancement projects, see Table III-10.
14 Note that ACR stands for Asset Condition [and Reliability] Refurbishment and LER for Life Extension Refurbishment.

The projects in Table III-7 list SG080 initiated projects but the scopes, estimated costs, and construction schedules are still under development. Most of these projects are in "Step 0" of our Project Management process. Step 0 is the project identification and conceptual engineering stage.

Table III-7.
SG080 Projects Initiated

Project Number	Title	Projected Construction FY
C03422	[redacted]	TBD
C21694		TBD
C24361		TBD
C27422		TBD
C27425		TBD
C27429		TBD
C27436		TBD
C27437		TBD
C30889		TBD
C30890		TBD
C33014		TBD

The relative reliability rankings were as follows (larger numbers signify better reliability performance):

Table III-8.
Reliability Rankings for SG080 Projects in the Initiated Stage

Circuit ID	Circuit Name	2009 Rank	2008 Rank
T1510	[redacted]	6	5
T5770		5	9
T3340		7	8
T1160		34	20
T1170		16	17
T1280		4	3
T1950		Double circuit efficiency	
T1340		11	29
T1660		31	13
T1780		38	42
T3320		25	18
T3330		Double circuit efficiency	
T1860		14	39
T4210		19 (Bulk)	9 (Bulk)
T1530		3	1

A number of placeholder projects have been tentatively identified for initiation in future years pending further review, reliability ranking at the time conceptual engineering starts, and the field evaluation results. As of this time, project scopes, estimated costs, and construction schedules have not been determined.

Table III-9.
Tentatively Planned SG080 Refurbishment Projects

Proj Number	Driver or Strategy	Title[15]	Projected Construction FY
CNYAS48	SG080	[redacted]	TBD
CNYAS50	SG080		TBD
CNYAS51	SG080		TBD
CNYAS52	SG080		TBD
CNYAS53	SG080		TBD
CNYAS54	SG080		TBD
CNYAS55	SG080		TBD
CNYAS56	SG080		TBD
CNYAS57	SG080		TBD
CNYAS58	SG080		TBD
CNYAS60	SG080		TBD
CNYAS62	SG080		TBD
CNYAS75	SG080		TBD
CNYAS76	SG080		TBD
CNYAS77	SG080		TBD
CNYAS82	SG080		TBD
QUEUE	SG080		TBD
QUEUE	SG080		TBD
QUEUE	SG080		TBD
QUEUE	SG080		TBD

The projects in Table III-10 were initiated as a result of the Lightning Performance Reliability Enhancement Strategy (SG048). This strategy was later superseded by Strategy SG080.

15 ACR stands for Asset Condition (and Reliability) Refurbishment and LER for Life Extension Refurbishment.

Table III-10.
Lightning Enhancement Projects

Proj Number	Driver or Strategy	Title	Projected Construction FY
C24359	SG048	Browns Falls-Taylorville 3-4 Lightning Enhancements T3080-T3090	FY2010/11
C24360	SG048	Coffeen-Black River-Lighthouse Hill 5 T2120 Lightning Enhancements	FY2010/11

Other remedial actions include a detailed condition assessment report on the New Scotland – Leeds – Pleasant Valley transmission corridor, which is a key transmission corridor that facilitates considerable transfer capability between New York's upstate and downstate transmission system, was recently completed. This report reviewed a variety of dimensions that impact this corridor's reliability performance, such as:

- Opportunities for reducing exposure to cascading structure failure
- Opportunities for reducing the number of transmission crossings
- Tensile and torsional ductility tests on phase conductors
- Assessment of lightning performance
- Wind analysis to determine whether the current design criteria is still valid

Additional information is included as Exhibit 2.

Reliability improvements resulting from the aforementioned overhead line refurbishment strategies will be gradual and long term in nature. An analysis performed in conjunction with Transmission Operational Planning and Review during the second half of FY 2007/2008, indicated that reliability improvement from this strategy will take a minimum of five years to begin to occur due to project lead-times (interim reliability declines may occur). For example, in approximately 10-12 years the reliability improvements for the 115 kV class should move out of the 4th quartile towards first quartile.

Increased maintenance activities will be implemented in parallel with long term SG080 projects to reduce short term reliability decreases and possibly provide interim shorter term reliability improvements.

This overhead line refurbishment strategy approach targets both wood pole and steel structure lines. Standard refurbishment categories have been established: safety, life extension, and full refurbishments. Full refurbishments of predominately steel structure lines would be targeted to reliably last for about 40 years. Predominately wood structure lines would be targeted to reliably last for about 30 years. Life extension refurbishments seek to improve reliability and extend the useful life of a line by 15 years. Safety refurbishments seek to safely secure a line for five years until a more comprehensive refurbishment can be completed. A safety refurbishment is often pursued when imminent safety concerns need to be addressed. Safety refurbishments will sometimes precede more comprehensive Article VII or Part 102 refurbishments.

Summary

The aging overhead line assets in New York point toward decreasing reliability as normal environmental, mechanical and electrical wear results in a failure to meet the original design codes under which these assets were built. A long term, systematic refurbishment approach is required to deal with overhead line reliability issues. The overhead line reliability strategy SG080 seeks to do that over the next 25 years. Reliability impacts due to the overhead line refurbishment strategy will be gradual and long term in nature. Increased maintenance activities will be undertaken in parallel with long term projects to reduce short term reliability decreases and possibly provide interim shorter term reliability improvements.

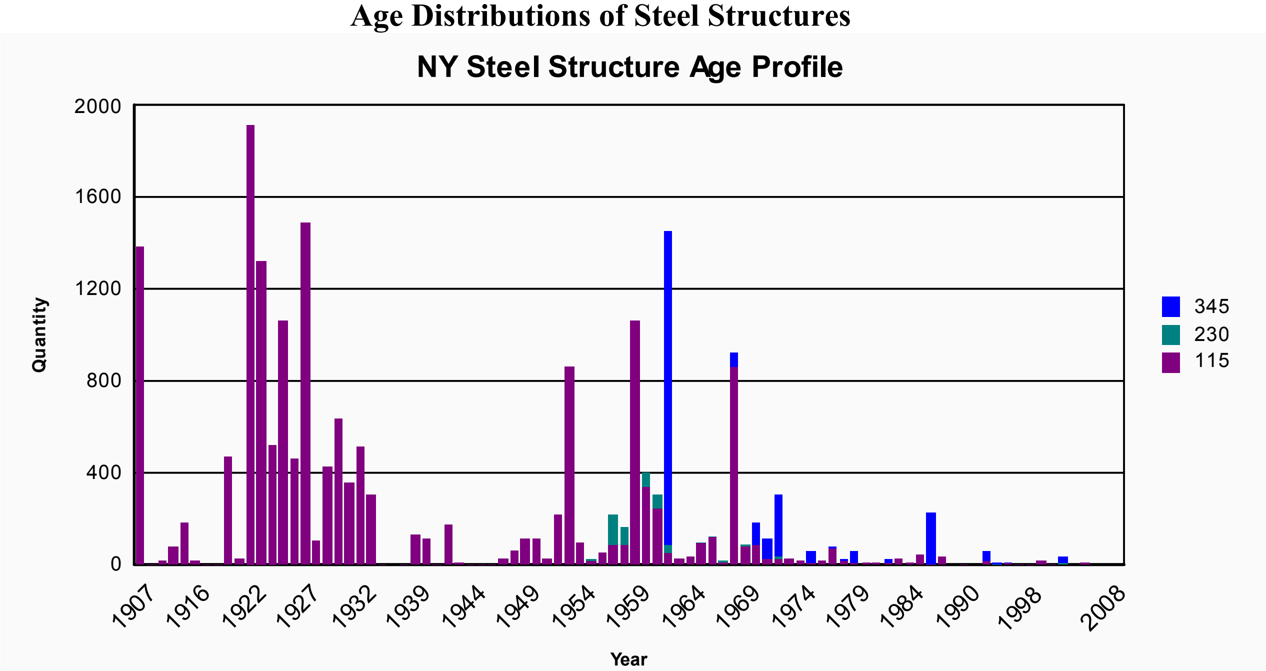
Structures

This section discusses steel structures, wood poles and foundations. Currently, there are 20,325 steel structures (17,448 towers and 2,877 poles), 35,703 wood poles, and many steel and concrete foundations across National Grid's service territory.

Steel Structures

Based upon plant accounting records, the age distribution of steel structures is given in Figure III-2. This figure shows an age population of steel structures owned by the Company. A significant portion of these assets are into the anticipated replacement timeframe of 70 years old (installed in 1939) to 110 years (1899).

Figure III-2
Age Distributions of Steel Structures



RW Beck/Mott MacDonald conducted an initial condition steel tower assessment of steel structures in FY 2004/2005. In a follow-up effort during FY 2005/06, Mott MacDonald completed an evaluation of 32 transmission lines using high resolution aerial photographs. The "Mott MacDonald" aerial study still serves as the basis for executing the steel tower strategy (SG018) projects discussed in this section. This follow-up study involved a review of over 4,000 photographs. Towers were graded in accordance with the criteria in Table III-11.

Table III-11
Visual Rating Categories

Description	Visual Grade
Fully painted – overcoat and undercoat intact Fully galvanized – coating intact	1
Paint coating over all surface – overcoat may not be intact and some very small areas (<1 percent) of light corrosion may be present. Galvanizing intact except for some very small areas (<1 percent)of light corrosion	2
Very light surface corrosion, majority of coating intact	3
Light pitting – possibly some very light edge roughening. Loss of greater majority of coating and zinc layers. Corroded surface would dominate surface preparation.	4
Significant pitting – loss of section clearly visible, edges feathered/thinned	5
Perforated element – severe physical damage	6

Based on the Mott MacDonald evaluation, Table III-12 identifies the steel tower transmission lines requiring refurbishment and the projects and project planned.

Table III-12.
Mott MacDonald Aerial Photography Evaluation Result Recommendation

LIF Order[16] (Risk Rank)	Circuit IDs		Follow-up Plans		Line
			Project Plans	Primary Basis for Action	
1 (146)	T2090		CNYAS67	SG018	[redacted]
2 (31)	T5180	T5230	CNYAS72 & CNYAS73	SG018	[redacted]
3 (200)	T2270		CNYAS68	SG018	[redacted]
4 (170)	T2320		CNYAS70	SG018	[redacted]
5 (94)	T1280	T1310	C04718 & C27425	SG080	[redacted]
7 (221)	T4260		In Queue	SG018	[redacted]
8 (3)	T2610	T2630, T2220, T2300	C21693	SG018	[redacted]
9 (37)	T1090	T1100	CNYAS62	SG080	[redacted]
10 (69)	T1500		C27431	SG018	[redacted]
11 (41)	T1380		CNYAS64	SG018	[redacted]
12 (77)	T1850		C21376	SG018	[redacted]
13 (49)	T1260	T1270	C03389	SG080	[redacted]
14 (42)	T1620		C27432	SG018	[redacted]
15 (48)	T1340		C27429	SG080	[redacted]
16 (74)	T1540	T1550	C18670	SG080	[redacted]
17 (85)	T5070		CNYAS71	SG018	[redacted]
18 (196)	T2290		CNYAS69	SG018	[redacted]
19 (36)	T5750	T5760	Luther Forest	Planning	[redacted]
20 (34)	T5770		C21694	SG080	[redacted]
21 (76)	T1160	T1170	C27422	SG080	[redacted]

As shown in Table III-12 (above) and Table III-13, a number of placeholder projects have been tentatively identified for initiation in future years pending further review and the field evaluation results.[17] As of this time, project scopes, estimated costs, and construction schedules have not been determined. The sequence will be mapped out during the second half of FY2009/10.

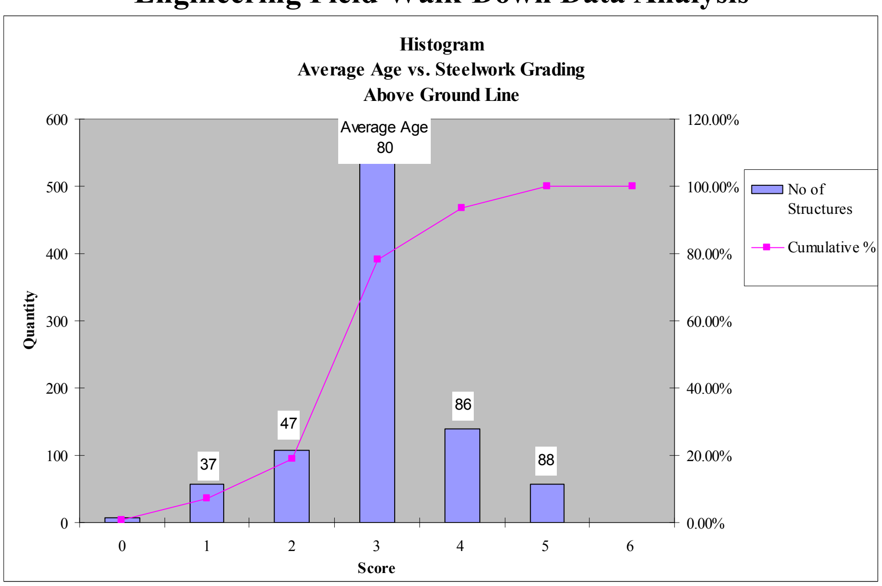
[16] Sequential order is based upon the relative Line Importance Factor (LIF) at the time of the study
[17] Placeholder projects are identified as CNYAS in the tables.

Table III-13.
Other SG018 Steel Tower Refurbishment Recommendations

Circuit IDs		Follow-up Plans: Project Plans	Follow-up Plans: Primary Basis for Action	Line
T5390		C31134	SG029	[redacted]
T1730		C21692	SG018	[redacted]
T1510		C03422	SG080	[redacted]
T1620		C27432	SG018	[redacted]
T1340		C27429	SG080	[redacted]
T1500		C27431	SG018	[redacted]
T1530		C03417 & C33014	SG080	[redacted]
T2270		CNYAS68	SG018	[redacted]
T1860		C30889	SG080	[redacted]
T1590	T1600	CNYAS66	SG018	[redacted]

After the follow-up aerial study by Mott MacDonald, the Company conducted field walk-downs on a number of transmission lines. Looking at the analyses in Figure III-3, once a structure reaches Visual Category 4—structural deterioration occurs rapidly (regardless of past painting or maintenance). With limited data, it appears the total time to go from Visual 4 to 6 may be on the order of 10 years. Over the long term, further information will need to be statistically analyzed in order to generate a more accurate degradation model.

Figure III-3.
Engineering Field Walk-Down Data Analysis



The results of routine five year walk down inspections are provided in Table III-14.

Table III-14.
Steel Structure Visual Grades

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

An appropriate priority code is also assigned when a steel structure is inspected. Funding Order C25539 is a blanket funding order established to replace steel towers identified as Visual Grade 6. Engineering is underway for these towers.

Condition and Performance Issues

At the time Strategy SG018 was written, five failures of steel structures on the New York Transmission system attributable to poor condition were identified.

- April 2003 - a tower on the [redacted] 115kV Line in Western NY toppled during an ice storm. Deterioration at the base of the tower contributed to this failure.
- September 2003 - National Grid replaced a deteriorated steel tower on the 115 kV [redacted] 151-152 transmission line.
- February 2004 - a line mechanic climbing on a tower on the [redacted] line partly fell when a corroded steel support gave way.
- June 2004 - the 115kV [redacted] line, tripped and locked out due to failed cross arms on two towers.
- March 2009 - the T2240 [redacted] 8 115 kV circuit tripped and locked out due to the failure of tower #435. Tower #435 is a square based steel lattice tangent suspension tower. The tower was located in a detention pond at a former chemical manufacturing plant. The failed tower was in approximately four feet of water. Due to the deep water, the base of the tower could not be removed for examination. This limited the ability of foot patrols to conduct routine inspections and footer repairs.
  - The failed tower was replaced with a wood pole structure. Failure Analysis FA0033, dated March 2009, recommended that the condition of the remaining towers in the detention pond should be inspected for damage and repaired accordingly. In addition, a long term project to assess the safety and reliability of transmission lines in this site is included as a placeholder in Table III-18

Remedial Actions Performed and Planned

Strategy SG018 Version 2, entitled Mitigating NY 115 kV Steel Structures approaching end of useful life, was approved in December 2005. SG018 Version 2 initially concentrated on critical crossings and the circuits believed to be in the worst condition. Based upon engineering field walk-downs conducted by Transmission Line Engineering, Project Funding Order C04636 resulted in a total of 171 structures being replaced throughout upstate New York. These replacements were done in calendar years 2006 through 2009.

Table III-15.
Steel Tower Critical Crossing Replacements

Line(s)	Total Number of Steel Towers Replaced
[redacted]	42
[redacted]	11
[redacted]	35
[redacted]	1
[redacted]	10
[redacted]	7
[redacted]	15
[redacted]	24
[redacted]	3
[redacted]	4
[redacted]	4
[redacted]	1
[redacted]	2
[redacted]	11
[redacted]	1
Total:	171

In addition to the replacements indicated in Table III-15, the South Oswego- Lighthouse Hill project scope includes 38 structure replacements, some of which are critical crossing structures. Due to outage constraints on these lines, replacement of the critical crossing structures was combined with project C21693. (Interim measures were taken to temporarily reinforce and secure these towers.).

The following table shows active refurbishment projects that are tied back to the Steel Tower Strategy (SG018):

Table III-16.
Existing SG018 Driven Projects

Project Number	Driver or Strategy	Title[18]	Projected Construction FY
C21376	SG018	[redacted]	FY2009/10
C21692	SG018	[redacted]	Cancelled
C21693	SG018	[redacted]	FY2010/11
C27431	SG018	[redacted]	TBD
C27432	SG018	[redacted]	TBD

Funding Project C21692 was cancelled following a ground based engineering field walk down of the Niagara-Packard 191 line. The steel towers were found to be in good structural condition. The following projects are planned for initiation over the next five to ten years. The sequence is being tentatively mapped out during the second half of FY2009/10.

Table III-17.
Planned SG018 Driven Projects

Project Number	Driver or Strategy	Title	Projected Construction FY
CNYAS63	SG018	[redacted]	TBD
CNYAS64	SG018	[redacted]	TBD
CNYAS66	SG018	[redacted]	TBD
CNYAS67	SG018	[redacted]	TBD
CNYAS68	SG018	[redacted]	TBD
CNYAS69	SG018	[redacted]	TBD
CNYAS70	SG018	[redacted]	TBD
CNYAS71	SG018	[redacted]	TBD
CNYAS72	SG018	[redacted]	TBD
CNYAS73	SG018	[redacted]	TBD
CNYAS74	SG018	[redacted]	TBD
QUEUE	SG018	[redacted]	TBD
QUEUE	SG018	[redacted]	TBD

[18] Note that STR stands for Steel Tower Refurbishment and ACR for Asset Condition [and Reliability] Refurbishment.

Table III-18.
Failure Analysis Driven Steel Tower Projects

Project Number	Failure Analysis	Title	Projected Construction FY
QUEUE	FA0033	[redacted]	TBD
QUEUE	FA0033	[redacted]	TBD

The Steel Tower Painting and Replacement Strategy (SG052), approved in February 2006, provided guidance for the painting and replacement of steel structures in New York. SG052 looked at the long-term steel tower replacement needs for the remainder of circuits not covered by the Steel Tower Strategy (SG018) in New York. A 15 year accelerated interim steel structure-painting program is now underway. Once this is completed, the painting of transmission steel structures will follow a 20 year cycle.

In addition to the painting program, Transmission continues a 20 year footer inspection and repair program. This program systematically inspects foundation above and below grade and repairs damage, primarily on a line-by-line basis.

The Overhead Line Refurbishment Strategy (SG080) was approved in March 2008. This strategy began a major asset replacement program over a twenty-five year period. The present phase of the strategy focuses primarily on refurbishing circuits that fall within the 40 worst performing circuits. This approach targets both wood pole and steel structure lines.

SG080 will absorb longer-term steel tower replacement projects that might have been previously planned under SG018.

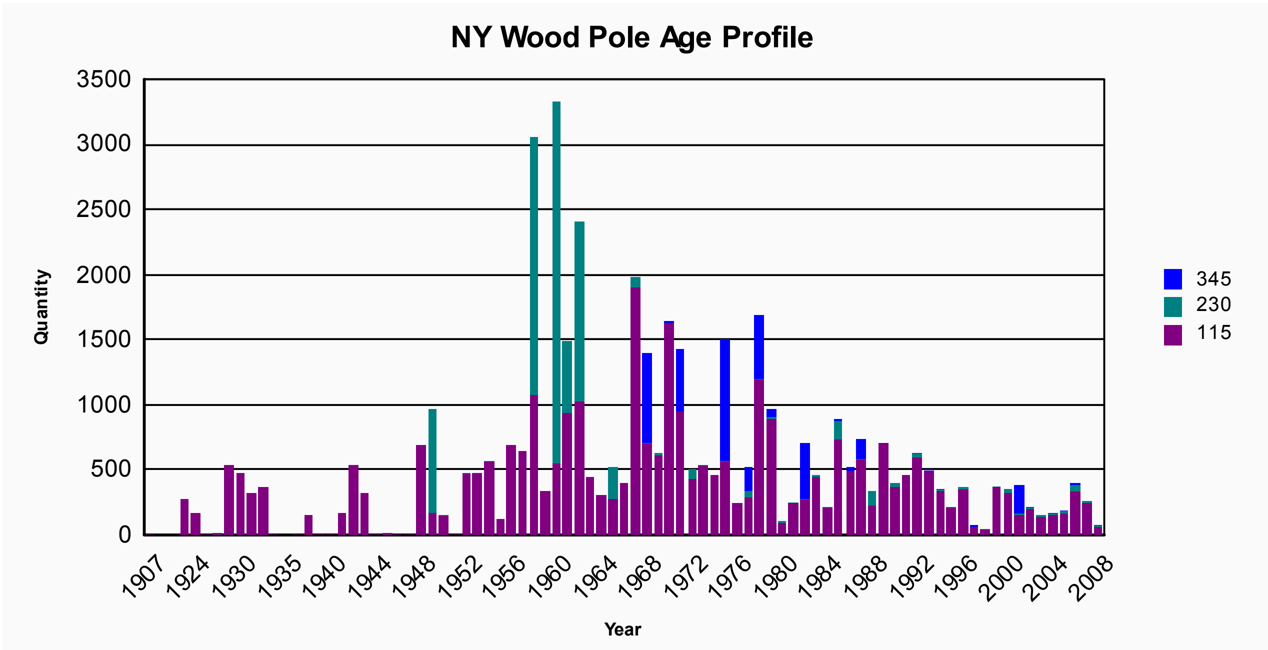
Summary

The aging steel structures continue to present challenges. While structural failures have been relatively rare, these failures do pose public safety risks that need to be minimized. The steel structure mitigation strategy SG018, steel tower painting and replacement strategy SG052, the overhead line refurbishment strategy SG080, and inspection and maintenance program developed by the Company provide a multi-faceted approach to address this challenge.

Wood Poles

The age distribution of wood poles is provided in Figure III-4. Most of these assets are within the anticipated replacement timeframe of 24 years old (installed in 1985) to 100 years old (1909).

Figure III-4.
Age Distribution of Wood Poles



Condition and Performance Issues

National Grid inspects and treats the ground line of wood poles and structures on a 10 year cycle. In addition, routine visual inspections of the entire structure are conducted once every five years. Wood poles and structures that fail to meet the obligatory National Electric Safety code are classified as "rejects." Severely deteriorated wood poles and structures are classified as "priority rejects."

In general, reject poles and structures only have two-thirds or less of their original strength. The greatest risk from reject poles and structures is the likelihood of failure during severe weather conditions. In addition to the safety implications associated with failures, this can hamper restoration efforts and increase outage lengths.

A review outage data from the past 10 years during the development of SG009 Version 2 identified only one reject pole-structure failure. On 22 March 1999, [redacted] failed. This structure contained a pole rejected by a ground line inspection conducted in the last quarter of 1991. Assuming a typical backlog of 370 poles and structures existed, a failure rate of 2.70×10-2 failures/reject pole-yr can be extrapolated.[19] That is, one failure would occur every 37 years. This level of failure is unacceptable and demonstrates the need to reduce the backlog to get the levels down to one that is as low as reasonably practical.

Priority reject poles and structures potentially can fail during "normal" weather conditions. For these type rejects, the residual strength of a pole can fall below one-third of

[19] This extrapolation is not using a statistically significant population size.

its original design strength. It is important to replace these poles and structures expeditiously. The safety and reliability risks from priority rejects are significant.

An analysis in 2007 examined historical inspection results at National Grid. Using this analysis, the following five to 10 year projections can be made:

Table III-19.
Result of the Analysis of Raw Inspection Data and Projected Rejects

Total No of Wood Poles in (based on Asset Register)	**35,703**
Reject %	1.55%
Priority Reject %	0.19%
5 Year Projection	
Reject	276
Priority Reject	34
Total	310
10 Year Projection	
Reject	552
Priority Reject	69
Total	621

The same 2007 analysis indicated that a danger exists that priority reject and reject rates will substantially increase over those projected by the "historical average" model (especially during the next 10-30 years). Table III-20 projections were based upon an analysis of wood poles and structures throughout US Transmission. The increasing average age of wood poles and structures strongly suggests associated increases in reject rates.

Table III-20.
Anticipated Numbers of Ground Line Rejects

Age Range	Age at now	Probability of Requiring Replacement After 10 Years
0-4	0	0.0%
5-14	10	0.0%
15-24	20	0.2%
25-34	30	1.1%
35-44	40	4.3%
45-54	50	12.6%
55-64	60	29.2%
65-74	70	54.0%
75-84	80	79.3%
85-94	90	94.8%
95-104	100	99.5%
105-114	110	100.0%
115-124	120	100.0%

Woodpecker damage is reported to be a growing problem due to the increasing woodpecker population. The national population of Pileated Woodpeckers, as reported by the U.S. Fish and Wildlife Service's Breeding Bird Survey data (1966-1999), is significantly increasing at a rate of 1.4 percent per year. A new wood pole and structure inspection criteria (per Strategy SG009, Version 2) was implemented at the end of 2007. As woodpecker damaged poles are identified, an appropriate priority code and repair timeframe is assigned (Exhibit 3). Progress is then tracked on an overall basis.

Chemanite treated poles were installed on the [redacted] line in 2004 as a pilot program. Unfortunately, the woodpeckers returned to these poles indicating Chemanite is just as susceptible to attack in upstate New York.

Reject poles and structures have not always been replaced when identified. A backlog of about 500 reject poles and structures dating over 10 years existed initially after the merger, much of which has been addressed. Based upon the 10 year ground line inspections, problem identification worksheets (PIWs), and the five year ground based visual inspections, a volume of approximately 228 reject poles exist in the upstate New York transmission system.

Aging wood pole structures approaching NESC code reject levels will be more susceptible to severe weather failures. In addition to the safety implications associated with failures, this can hamper restoration efforts and increase outage lengths.

Below is a brief summary of pole failures that occurred over the last year:

- June 2009 - the T6400 [redacted] 115 kV line tripped and locked out due to the static wire making phase contact as the result of a pole top failure.
- February 2009 - a pole fire at structure [redacted] line lead to a crossarm failure which resulted in a line lockout.

Remedial Actions Performed and Planned

In October 2007, a comprehensive wood pole management strategy (SG009, Version 2) was approved. The goal of this strategy is to ensure ground line reject poles, woodpecker damaged poles, insect, and rotting wood structures are replaced in a timely manner.

Out of the present backlog of 228 poles in Table III-21, about 174 will be replaced through the wood pole management program.[20] The remainder will be addressed through SG080 projects.

Solely relying on the wood pole management strategy to manage wood pole structures is not the optimal solution with an increasing average age profile.[21] Structure replacements will be scattered throughout the transmission system. This is acceptable when the percentages of rejects are relatively small. However, as the wood pole population increases in age, the

[20] Outstanding reject poles with a construction package issued with plans for replacement by the end of calendar year 2009 are not included in this list.
[21] SG009 (version 2)

percentages will increase. In order to maintain the long-term sustainability of the Company's transmission lines a long-term approach is needed. For example, an average of 1.5 percent of the circuits will require refurbishment each year if a 65 year design life is assumed. That is, approximately five circuits per year.

The Overhead Line Refurbishment Strategy (SG080) was approved in March 2008. This strategy began a major asset replacement program over a twenty-five year period. The present phase of the strategy focuses primarily on refurbishing circuits that fall within the 40 worst performing circuits. This approach targets both wood pole and steel structure lines. Out of the backlog of 228 poles list, about 54 will be replaced through upcoming refurbishment projects.

Table III-21.
Volume of Reject Poles

Line Number	Line Name	Number of structures to be replaced	Number of rejected poles	Poles Number
T2350	[redacted]	7	7	151, 18, 19, 158, 182, 53, 126
T2140		6	6	30, 43, 28, 58, 192, 52
T2720		4	4	185, 111, 144, 184
T5250		4	4	427, 449, 145, 137
T3230		3	3	315-1, 132-2, 20
T5240		1	2	113
T2090		2	2	376, 381
T2100		2	2	39, 26
T4240		1	1	15
T5800		2	2	804, 724
T1570		1	2	20
T3380		1	1	7
T4160		1	3	2
T2290		1	1	839
T4010		1	1	200
T2300		1	1	22
T2480		1	1	92
T4110		4	4	50A, 44A, 19, 54
T5630		5	6	111, 110, 240, 239, 252
T2310		1	1	8052
T3000		1	1	32
T3330		3	3	1, 5, 19
T3330		1	1	23 R
T2710		1	1	30
T2580		1	2	137
T5920		1	1	635
T5700		1	1	509
T6400		1	1	208
T1890		32	33	38.9, 69, 202, 226, 229, 239, 241, 248, 250, 253, 254, 12, 19, 24.001, 26.001, 51, 63, 68, 77, 95.3, 107, 121, 129, 154, 160, 183, 187, 193, 200, 221, 222, 28_DupX
T1580		5	5	83, 65, 61, 24, 27
T1040		3	3	16, 28, 17, 46
T1550		2	2	1_DupX, 11
T1820		2	2	13, 13.2
T1050		1	1	10

Table III-21 (continued)
Volume of Reject Poles

Line Number	Line Name	Number of structures to be replaced	Number of rejected poles	Poles Number
T1810	[redacted]	1	1	13A
T1870		1	1	337
T1110		1	1	213
T2210		3	3	130, 243, 53
T1690		1	1	45
T1530		1	1	1.004
T1210		1	2	57A
T2600		14	14	2, 64, 66, 68,84, 89, 92, 97, 98, 100, 126, 153, 211 163_DupX
T1490		10	10	219, 167, 283, 311, 313, 316, 147, 129, 70, 48
T1490		2	2	36.4, 37
T2420		4	4	293, 223, 330, 121
T1620		5	5	25, 31, 30, 48, 42
T1500		6	9	40A, 59, 142, 142A, 272, 298, 298A, 299, 299A
T5080		3	3	187, 185 1/2, 184 1/2
T1340		5	5	284, 190, 165, 262, 127
T4270		1	1	30
T5810		8	8	43, 90, 2, 38, 56, 44, 40, 162
T2040		2	2	369, 382
T4210		41	44	642R, 630L&R, 701L, 614R, 623L, 706R, 694L, 692R, 691R, 687L, 686L, 682L, 661R, 709L, 332R, 326L&R, 325L, 309R, 305L, 303L, 367R, 336R, 350L, 346C, 280R, 232R, 279R, 291L, 296L, 290R, 396R, 416L, 385R, 379R, 372L, 419R, 500R, 497R&L, 474R, 467L,666L
	TOTALS	**214**	**228**	

The following are specific pole failure event remedial actions taken with a failure assessment by Transmission Line Operations and Maintenance Engineering:

- Transmission Line Services evaluated the condition of the [redacted] pole following the June 2009 failure and determined it to be in good condition. Failure Analysis FA0040, dated July 2009, indicated that this appears to be a one off event and not indicative of a systemic issue with this line.

- Transmission Line Services replaced the pole and cross arm following the T4200 [redacted] pole fire. Failure Analysis FA0031, dated March 2009, noted that pole fires "tend to occur after extended periods of wet weather."[22] An accepted theory is that "resultant charging current of the air coupling capacitance between the pole and the phase conductors uses the electrical conductance of the wet pole wood as a path to ground." Current densities tend to be highest near down lead fasteners and unbonded hardware. This can elevate temperatures at these locations resulting in pole fires. Unbonded hardware and down lead fasteners are spread too far apart are susceptible. A period of heavy soaking rains occurred in this area on February 22. Extreme pole fires such as this one can result if heating occurs in an area where ample oxygen is present such as at a pole check creating a "Chimney Effect."[23] Most pole fires are typically minor and some go unnoticed.

Summary

A low volume of reject poles is important for safety and reliability. Wood pole management strategy seeks to replace priority rejects within six months of identification and rejects within two years of identification.

The Overhead Line Refurbishment Strategy is complimentary to the wood pole management strategy. Both strategies manage wood pole structures as the wood pole population ages. As the wood pole population ages, the percentage of rejects is expected to increase. A separate, comprehensive line refurbishment effort on a line by line basis is the recommended approach for an aging wood pole structure population.

Foundations

Since 2005 Computapole field inspection data has been gathered on both steel and concrete foundations. This information is not available through the standard Computapole reports. According to EOP T007 condition ratings for steel foundation types are categorized by the following scale:

1-Serviceable
2-Intact
3-Light Corrosion
4-Light Pitting
5-Significant Pitting
6-Very Severe Deterioration

The results of foundation inspections are:

[22] G. E. Lusk and S.T. Mak, "EHV Wood Pole Fires: Their Causes and Potential Cures," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-95, no. 2, March/April 1976
[23] Dr. G. L. Johnson and B. F. Walraven, "Tentative 'Cure' for Transmission Pole Fires," Transmission and Distribution, October 1973

Table III-23.
Steel Foundation Inspection Results

Steel Foundations		**Inspection Results**	
Visual Grade	1	6,718	58.1%
Visual Grade	2	3,083	26.7%
Visual Grade	3	1,409	12.2%
Visual Grade	4	299	2.6%
Visual Grade	5	50	0.4%
Visual Grade	6	2	0.0%
Total		**11,561**	**100%**

Table III-23 includes inspections conducted from 2005 through mid-2009. An appropriate priority code is assigned when a foundation is inspected.

According to EOP T007 condition ratings for concrete foundation types should be categorized by the following scale:

1-Serviceable
2-Light Deterioration
3-Medium Deterioration
4-Severe Deterioration
5-Very Severe Deterioration
6-Not used[24]

Table III-24
Concrete Foundation Inspection Results

Concrete Foundations		**Inspection Results**	
Visual Grade	1	3,603	60.8%
Visual Grade	2	2,029	34.2%
Visual Grade	3	195	3.3%
Visual Grade	4	45	0.8%
Visual Grade	5	28	0.5%
Visual Grade	6	26	0.4%
Total		**5,926**	**100%**

An appropriate priority code is assigned when a foundation is inspected.

Steel grillage foundation usage started in the 1920s. This type of steel foundation comprises the majority of lattice structure foundation types.[25] However, some of the lattice

[24] Initially, the Visual Grade 6 was incorrectly used until better training and software measures were put in place to prevent this grade from being improperly used. The next cycle (beginning in CY2010) will correct these initial errors. The steel tower footer inspection and repair program and the planned overhead line refurbishments will mitigate these deteriorated foundations. A total of 26 concrete foundations were improperly graded with a 6. This total is down from 46 last year.

[25] Approximately 80 to 90 percent of these structures in New York

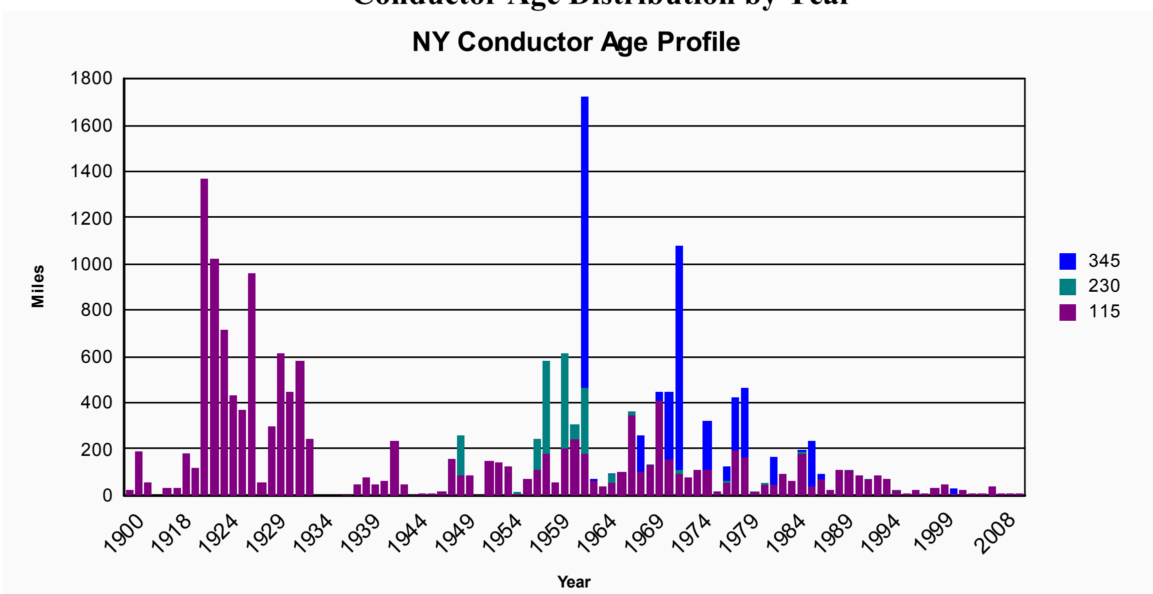
towers employed a battered type concrete foundation which has a limited amount of concrete exposed above the ground line.[26] The remaining foundations in New York are associated with steel poles and tend to be reinforced concrete—in the order of five to 10 percent.

Phase Conductor

The phase conductor asset group includes conductors, static wires and splices. There are 18,687 conductor miles (plant accounting records) across the National Grid service territory at voltage levels 115kV and greater. Specific inventory information regarding miles of static wires and splices are not available at this time.

Figure III-5 shows the age distribution of conductors in the service territory. Many conductors are within the anticipated replacement timeframe of 70 years old (installed in 1939) to 110 years (1899). The 115kV network is by far the oldest, with the oldest circuits being over 100 years old.

Figure III-5.
Conductor Age Distribution by Year

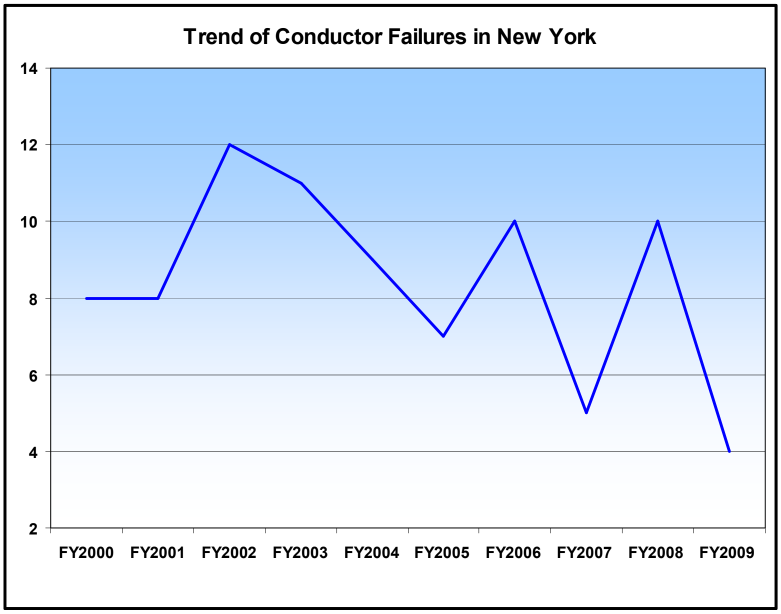


Condition and Performance Issues

The trend of conductor failures from FY1999/00 to FY2008/09 appears to be consistent or slowly declining in the direction of fewer failures (Figure III-6).

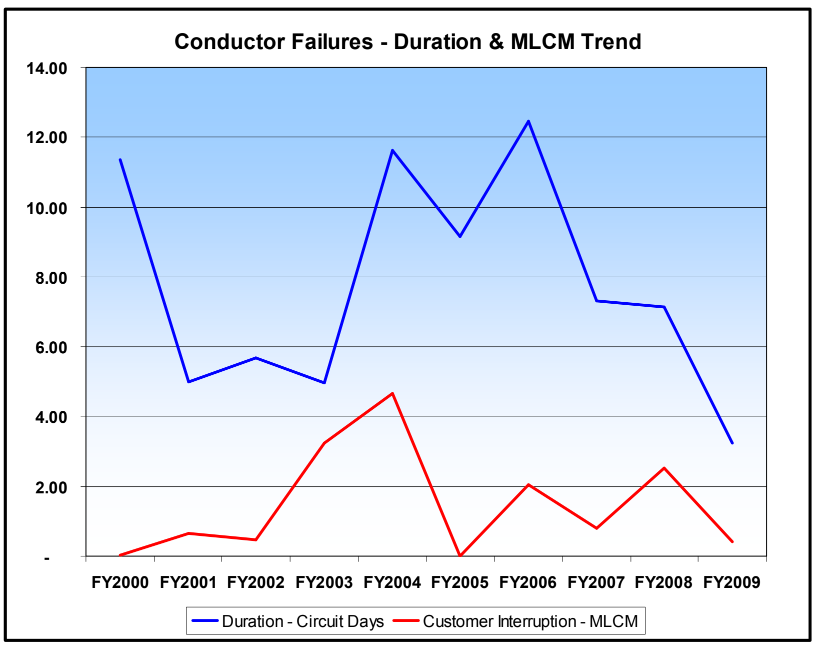
[26] Approximately five to 10 percent that were constructed prior to the use of the steel grillage design

Figure III-6.
Transmission Conductor Failures Long Term Trend



The total outage duration due to conductor failures in Figure III-7 broadly follows trend of failures with the rise of failure events, but the lost customer minutes trend shows much greater variability.[27]

Figure III-7.
Lost Customer Minutes Due to Conductor Failures



[27] Ranging from no loss of customer minutes to significant levels in millions of lost customer minutes, MLCM

The percent contribution to system outages from conductor failures has also risen over the past six years, though this failure mode is still low.

Table III-25 below lists those circuits where phase conductor condition might be a concern although statistically this may not be the case.

Table III-25.
Lines with Phase Conductor Failures

Circuit ID	Circuit Name	kV	# Conductor Failures (FY2005 – FY2009)
T1530	[redacted]	115	5
T1510		115	4
T1860		115	4
T4040		115	4
T5760		115	4
T2670		115	3
T1570		115	2
T4030		115	2
T5940		115	2
T1210		115	1
T1220		115	1
T1280		115	1
T1430		115	1
T1450		115	1
T1540		115	1
T1950		115	1
T2220		115	1
T3340		115	1
T4020		115	1
T4060		115	1
T5110		115	1
T6060		115	1

Many of the lines in Table III-25 have projects initiated or planned as a result of the Overhead Line Refurbishment Strategy (SG080) or the Steel Tower Strategy (SG018). However, the remaining circuits will be monitored to determine if condition based conductor refurbishment projects may be needed.

Below are summaries of conductor failures occurring over the last year:

- July 2009 - the [redacted] line tripped and locked out due to a conductor failure. Line patrol personnel observed that the conductor broke inside of the suspension clamp at structure #31.

- February 2009 - the [redacted] 115 kV circuit tripped and locked out due to a conductor failure. The failure occurred between tower #369 and #370 near a suspension tower attachment point.

- November 2008 - [redacted] line. The conductor failed adjacent to a tee-tap fitting which ties to the NYSEG Geneva tap line. The failure caused a jumper loop splice to pull apart allowing the span from tower #434 to #435 to contact the ground causing the line lockout.

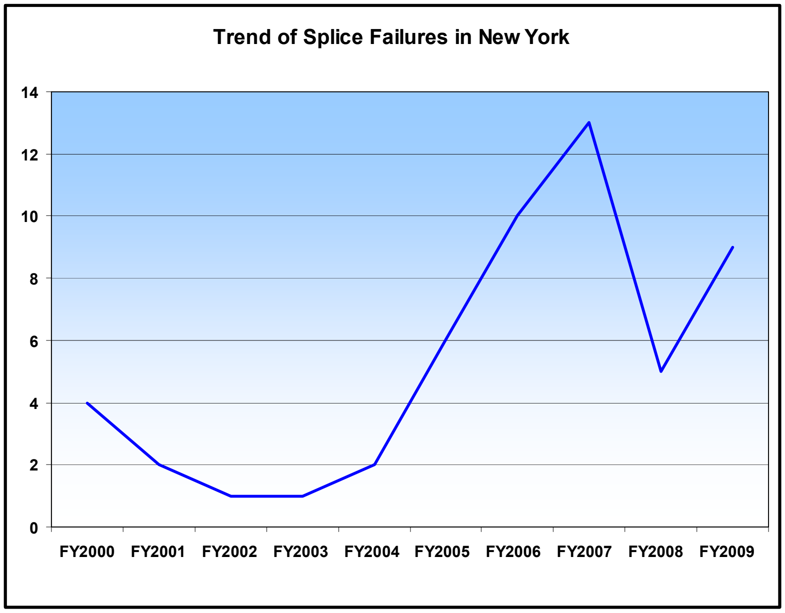
The trend of static wire failures indicates a decrease over the past two fiscal years (FY2007/08, FY2008/09) in this mode of failure after consistently increasing from FY2003/04, peaking in FY2006/07. While a decreasing trend has been observed over the past two fiscal years, future projects to replace strategically located static wire should proceed as scheduled to help ensure that the current decreasing trend can be sustained.

The trend of splice failures has been stable in the last two fiscal years following the high number of failures in the region. However, Figure III-8 shows that splice failures on transmission lines increased in FY2008/09 (FY2009 in the figure) following a sharp decrease during FY2007/08.

There are three general types of conductor splices used in the NY transmission system; ACSR (Aluminum Conductor Steel Support), AAC (All Aluminum Conductor), and copper conductor. Over time, expansion and contraction of a splice due to heating and cooling eventually allows for the penetration of oxygen and water. Once water and oxygen are present within the splice, the electrical interface between splice and conductor begins to break down increasing the resistance of the electrical interface. As electrical resistance increases so does the splice temperature. Eventually, the temperature of the splice will begin to rise and lead to failure if undetected. Elevated line operating temperatures and quality of splice installation are also factors that affect splice service life.

While there are more ACSR failures than AAC failures, the dataset is not large enough to conclude that ACSR splices are more prone to failure than AAC and for all intents and purposes, their rates are about equivalent. The data suggests that copper splices perform very well. To further address the issue of splice failures, a number of initiatives have been implemented. First, the frequency of Infra Red inspections has been increased to annual for all lines in NY. Second, Transmission Line Operations and Maintenance Engineering team has been formed to analyze the condition data and prioritize repairs. Summaries of the findings are provided later in this section.

Figure III-8.
Trend of Splice Failures



Below are summaries of splice failures occurring since September 2008:

- July 2009 - the [redacted] line tripped and locked out due to a failed jumper loop splice on the [redacted] sub tap line.
- May 2009 - the [redacted] line tripped due to a failed jumper loop splice at tower #65.
- April 2009 - the [redacted] line tripped and locked out due to a splice failure near [redacted] in Fort Orange, NY.
- January 2008 - the [redacted] 115 kV circuit tripped and locked out due to a splice failure between structure #10 and #11.
- December 2008 - this incident resulted from a failed full tension splice between structure #118 and #119 on [redacted]
- December 2008, the [redacted] line tripped and locked out due to a splice failure between structure #306 - #307.
- December 2008 - the [redacted], 115 kV line tripped and locked out due to a splice failure between structure #613 and #614. A second splice failure occurred on another day in December in the same section. .
- November 2008 - a compression splice failed on the [redacted] line causing a line lockout.

Remedial Actions Performed and Planned

For phase conductor remedial actions an initial clearance study were completed using ground survey measurements. Subsequent aerial laser surveys have been completed on 75 percent of the transmission system. The remaining aerial surveys will occur in CY 2009 and 2010. Analysis of the survey data has been completed on 50 percent of the transmission system. Analysis will continue in parallel with the aerial surveys and is expected to be completed in CY 2011.

The Transmission Ground Line Clearance Strategy (SG029, Version 3), approved in April 2009, outlines an approach for addressing substandard spans. The conductor clearance strategy intends to bring up to code the group of transmission lines with the highest overall clearance risk first, then progressively address lines by level of overall risk. To accomplish this, each span is assigned a risk level. Level 4 spans successfully meet the National Electric Safety Code, or NESC. Spans meeting the governing NESC code would be left "as is" except where deemed important to enhance public safety (principally, spans over roads, railways, and navigable waterways). Level 3, 2, and 1 substandard spans have varying degrees of risk. A Level 1 span has the highest risk and Level 3 has the lowest risk. Risk is based upon several factors:

- the quantitative measure by which a span does not meet the minimum code clearance requirements,
- the anticipated loading level, which impacts clearance levels, and
- the location of the span

Conductor clearance refurbishment (CCR) projects will be set up for candidate lines with the highest overall cumulative risk scores. In some cases (for abnormally high outlier risk span), individual spans projects will be set up. During these CCR projects, Level 1 and 2 spans will be brought up to code as part of the conductor clearance strategy. In other cases, conductor clearance work may be bundled into an existing project for efficiency. Level 3 substandard spans will be corrected under the systematic, long-term, Overhead Line Refurbishment strategy (SG080).

Table III-26 lists the CCR projects initiated as a result of the Conductor Clearance Strategy (SG029 Version 3). The project scopes, estimated costs, and construction schedules are being now being developed.

Table III-26.
Existing SG029 Driven Conductor Clearance Refurbishment Projects

Project Number	Driver or Strategy	Title
C31129	SG029	[redacted]
C31130	SG029	
C31131	SG029	
C31132	SG029	
C31134	SG029	
C31135	SG029	
C31136	SG029	
C31137	SG029	
C31138	SG029	
C31141	SG029	
C31145	SG029	
C31146	SG029	
C31147	SG029	
C31148	SG029	
C31149	SG029	
C31150	SG029	
C31151	SG029	
C31152	SG029	
C31153	SG029	
C31154	SG029	
C31155	SG029	
C31156	SG029	

For projects listed in Table III-26, the goal is to complete these projects over the next two to four years. A list of future projects is being developed.

Funding Project C16091, bringing the substandard span for Volney-Clay 6 structures 178-179 and Nine Mile Point 1 – Clay 8 up to code, was completed in January 2009. In addition, Funding Order C03256, was approved to address certain substandard spans on the Black River – Lighthouse Hill 5 & 6 circuits up to code. Work was completed in June 2007.

Specific conductor failure event actions and plans following the event and/or the assessment are discussed below:

- [redacted] Conductor Failure - The insulators at structure #31 were changed in March 2009 by a contractor. The suspension clamp was not changed at this time since there were no indications of a deteriorated connection. The conductor also had an armor type cover which concealed the weakened conductor. It was not possible to obtain the suspension clamp for analysis, however this failure is similar to failures experienced on the [redacted] and [redacted] lines. It was concluded that conductor arc damage was caused by insulator flashovers due to lightning at locations where suspension clamps have loosened. There have been five conductor failures recorded for the [redacted] lines since 2005. Failure Analysis FA0041, dated August 13, 2009, further recommended the review of corona inspections for the [redacted] lines to see if weakened conductor inside of the suspension clamps can be detected through excess corona emissions.

- [redacted] Conductor Failure - The event of February 2009 led to the replacement of a short section of the conductor. Failure Analysis FA0030, dated March 2009, concluded that conductor fatigue due to Aeolian vibration was responsible for the failure. Due to the conductors in service life of 87 years and the lack of anti-vibration devices on the line, this failure is most likely indicative of a systemic issue on this line. The analysis recommended that a conductor assessment of this line be performed. The assessment will consist of taking conductor samples from the line and evaluating tensile strength, steel core wire integrity, and ductility testing. The assessment is scheduled to be completed during FY2009/10.

- [redacted] Conductor Failure - Following the conductor failure in November 2008, Transmission Line Services crews repaired the conductor and tee-tap fitting. Failure Analysis FA0021, dated January 2009, there have been four additional conductor failures on this line recorded since 2004. The failure analysis further indicated that the [redacted] line appears in need of major refurbishment work. This recommendation will be addressed in the SG080 overhead line refurbishment.

As a result of the Static Wire Strategy (SG073), the following projects have been initiated:

Table III-27.
Initiated SG073 Driven Projects

Project Number	Driver or Strategy	Line	Projected Construction FY
C28676	SG073	[redacted]	FY2010/11
C28678	SG073		FY2009/10
C28681	SG073		FY2010/11
C28707	SG073		FY2010/11
C28709	SG073		FY2010/11
C28710	SG073		FY2009/10
C28712	SG073		FY2010/11

Table III-28.
Static Wire Strategy Incorporated into Existing Projects

Project Number	Driver or Strategy	Line	Projected Construction FY
C03417	SG080	[redacted]	FY2011/12
C21693	SG018	[redacted]	FY2010/11

Specific static wire failure event remedial actions taken are discussed below:

- [redacted]- As a result of the May 2009 event, the structure was temporarily repaired. Permanent repairs will be performed in March 2010 during a scheduled static wire replacement project.

National Grid is investigating possible in-service techniques to determine the residual strength of the inner steel wire in ACSR splice conductors. Furthermore, the Company is considering a planned conductor sampling regime to obtain information on condition and residual life. Initial efforts have already been undertaken. To obtain the best information it will be necessary to retrieve samples from mid-span rather than jumper loops. However, this will have outage implications. National Grid continues to undertake forensic examination of failed components and conductor lines to identify wear-out mechanisms and possible failure modes.

Two initiatives have been implemented to address splice failure:

- Frequency of infrared inspections has been increased to once a year for all lines in New York. Critical circuits (bulk lines) received annual reviews and non-critical lines (usually load lines) were inspected on three year cycles. When a splice is identified as a "hot spot," it is replaced or repaired.

- A team has been formed to analyze the condition data and prioritize repairs. Recent failure analyses and recommendations have been included throughout the overhead line section.

Actions and plans resulting from splice failure are discussed below:

- [redacted]Splice Failure - As a result of the July 2009 event, Failure Analysis FA0042, August 2009, recommends avoiding the use of dissimilar metals for electrical joints whenever practical. When this cannot be avoided, it is recommended to use connectors that maximize surface area in order to help extend the service life of dissimilar metal joints.

- [redacted] Splice Failure - Failure Analysis FA0038, dated June 2009, indicated that this appears to be a one off event and not indicative of a larger issue.

- [redacted]Splice Failure. Failure Analysis FA0036, dated May 2009, recommended monitoring splices with slightly elevated temperature through normal inspection cycles and procedures per EOP T007.

- [redacted] 112 Splice Failure - Following the January 2008 failure, new conductor and splice was installed. Failure Analysis FA0029, dated March 2009, concluded that damage to the conductor at a location roughly 12 inches from the splice is responsible for the failure.

- [redacted]Splice Failure - Transmission Line crews replaced the splice and installed new conductor following this December 2008 failure. An analysis in March 2009 (Failure Analysis FA0027) indicated that this to be a one-off event initiated by a severe lightning event.

- [redacted]Splice Failure - Following the December 2008 splice failure, the line was repaired with a new splice and conductor. Failure Analysis 0026, dated March 2009, concluded that this failure appeared to be a one-off event due to lightning damage.

- [redacted] Splice Failure - Failure Analysis FA0025, dated March 2009, note that the age of the lines may indicate that the splices are nearing or possibly beyond their useful life. Two SG080 refurbishment projects will address this concern.

- [redacted] Compression Fitting Failure - This events and one other similar event, do not appear to be a systemic issue. However, the splices may be nearing or beyond their useful life given the age of the line. SG080 life extension project, which includes conductor splice replacements, will address this concern.

Summary

Conductors, static wire, and splice issues and failures can pose significant safety, as well as reliability problems. The conductor clearance strategy (SG029 Version 2) and the static wire strategy (SG073) specifically seek to address critical issues specific to this area. The overhead line refurbishment strategy (SG080) provides a systematic long term approach that will also address issues related to aging conductors, static wires, and splices. In addition, the formation of Transmission Line Operations and Maintenance Engineering provides for more aggressive strides to quickly tackle reliability related issues.

Insulators and Fittings

This asset group includes glass, ceramic and polymer insulators. Currently, there are no known condition or performance issues with ceramic and glass insulators. However, some polymer insulators are more prone to experience failures due to moisture ingress as a result of design and manufacturing defects. When moisture penetrates the insulator's sheath and reaches into the fiberglass core, this can result in failure due to a brittle fracture (which is a mechanical failure of the fiberglass) or flash-under (which is an electrical failure mode caused by tracking along or through the fiberglass rod). Catastrophic brittle fracture failures frequently result in the conductor dropping from the structure.

Remedial Action Planned

A strategy (SG078) recommending the replacement of all polymer insulators on the transmission system has been approved. It is anticipated that all the polymer insulator replacements will be completed by 2012.

Summary

The catastrophic failure of a polymer insulator impacts both the reliability and public safety of a line. It will be important to replace polymer insulators with the potential for failure in a systematic way. A program to accomplish this is in the final stages of development.

Underground Cables and Related Equipment

National Grid's underground cable network is composed of fluid filled cable, pipe-type cable and solid dielectric cable systems. National Grid has 51.8 miles of underground cable in-service within the service territory of which approximately 83 percent of underground cables are high-pressure fluid filled pipe-type (Table III-29). Over one third of the Company's underground cable assets are between 40 and 59 years of age (Figure III-9 and Table III-30).

Table III-29.
Underground Cables Miles by Voltage

	115kV	230kV	345kV	Total
Low Pressure[28]	0	0.4	0	0.4
High Pressure	22.1	20.2	0.7	43.0
Solid Dielectric	8.4	0	0	8.4
Total	**30.5**	**20.6**	**.7**	**51.8**

[28] The 0.4 miles of LPFF 230kV cable is not in-service, but retired in place. There is currently a project to remove this cable due to environmental concerns.

Figure III-9.
Underground Cable Age Profile

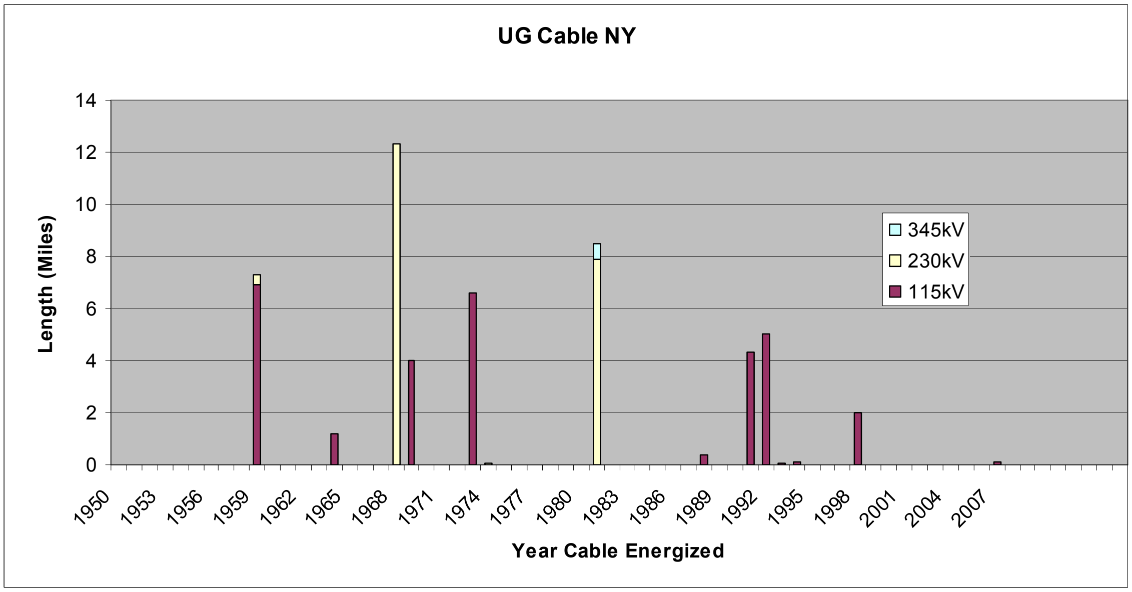


Table III-30.
Asset/Age Profile Underground Cables

Asset/Age Profile (Years)	0-19	20-39	40-59	60+	Total
Underground Cables	13	10	13	0	36

The majority of the cable pressuring plant equipment is of similar vintage to the high pressure fluid filled pipe-type cable. Given that these are mechanical type systems, age related problems are anticipated.

Condition and Performance Issues

High Pressure Fluid Filled cables are in steel pipes with large dielectric fluid volumes and large volume reservoirs. There are environmental risks regarding the potential release of oil from these types of fluid filled cables. These cables have the potential to create significant environmental concerns if adequate maintenance is not carried out routinely on these systems. While the likelihood of oil leaks is rare, the consequential release volumes can be significant. The two major maintenance items to be monitored on this type cable is the cathodic protection systems and the pressurizing plants. Routine inspections are performed on the cathodic protections systems. Bi-monthly visual and operational (V&O) inspections are performed on the pressurizing plants. Some specific concerns have been identified regarding some cathodic protection systems and some pressurizing plants.

Solid Dielectric cables were installed in the late 80s and early 90s and have a low mile weighted average age profile. At this time, solid dielectric cables do not appear to have condition issues. Cable terminations are inspected as part of the V&O inspection at the substation. Manhole inspections are performed periodically. Based on this operational history, current monitoring is considered sufficient. No specific condition concerns have been raised.

With regard to pressurizing plant and equipment, a detailed pumping plant condition assessment is scheduled for this fiscal year. This condition assessment will be undertaken by external cable manufacturers and will form the basis of any future remedial works.

Table III-31 lists the locations of the pressurizing plants, cables served, manufacturer, and reservoir size.

Table III-31.
Pipe Type Cables – Pressurizing Plants, Gas Cabinets, Crossover Assemblies

Station	City	Cables Served	Manufacturer	Reservoir Size (Gal)
[redacted]	Tonawanda	[redacted]	Jerome	15,000
	Buffalo		Jerome	5,500
	Buffalo		Jerome	NA - Crossover Cabinet
	W. Seneca		Jerome	5,500
	Rochester		Jerome	3,500
	Onondaga		Salter	2,500
	Syracuse		Jerome	4,000
	Syracuse		Jerome	4,000
	Oswego		Pikwit	4,000
	Albany		Pikwit	8,000

Cathodic protection systems are part of underground cable network. A cathodic protection system is the primary protection against corrosion of the steel pipe. Without cathodic protection, the condition of the pipe will deteriorate over time due to corrosion, resulting in fluid leakage and potential subsequent electrical failure. The company found systems in various states of deterioration in Buffalo locations. Specifically, [redacted] and [redacted] substations, [redacted].

Table III-32 provides a list of the type of cathodic protection systems installed on each of the high pressure fluid filled pipe type cable systems.

Table III-32
Cathodic Protection System Summary

Cable	Location	Rectifier and Polarizing Resistor	Rectifier and Polarization Cell	Rectifier and Solid State Isolator	Notes
[redacted]	NY West		X		Project to install solid state isolators.
[redacted]	NY West		X		Project to install solid state isolators.
[redacted]	NY West			X	
[redacted]	NY Central			X	
[redacted]	NY East			X	
[redacted]	NY East		X		
[redacted]	NY Central	X			
[redacted]	NY Central	X			
[redacted]	NY Central	X			
[redacted]		X			
[redacted]			X		
[redacted]			X		

Lastly, Sheath Voltage Limiters (SVLs) limit the voltage rise on a cable sheath and its bonding lead that could occur during switching transients, lightning surges and cable termination flashovers. There are very few installations of SVLs in the service territory and no specific condition concerns have been raised.

Remedial Actions Performed and Planned

There is a spares list for cables in New York (Exhibit 4). Several gaps in spare material were previously identified for the New York circuits. To fill in these gaps, additional material was purchased. During 2007, two 345kV repair splices were ordered and delivery occurred in the fall of 2008. The repair splices will allow existing material located in New England to be used in the event of a 345kV cable failure in New York. A single reel (1500') of 115kV pipe-type cable was also ordered to serve as a universal spare for all of the New York 115kV pipe-type cables. The cable was delivered in the fall of 2008. It is anticipated that additional materials, (cable, splices, terminations) may need to be ordered to ensure proper recovery from cable failure events. Specification development for these additional materials is in progress.

In prior years, concerns were expressed about the lack of a formal pump and auxiliary equipment preventative maintenance program. Electric Operating Procedure (EOP T009) was developed to formalize the maintenance requirements of the cable systems. The requirements of this EOP are incorporated into the Substation & Maintenance AIMMS/CASCADE system for implementation and tracking.

In the 2008 Asset Condition report, the Company identified a pressurizing plant at the Rochester Airport as approaching end of life and presented a possible reliability risk. Engineering design for a replacement plant will be completed in FY2010 and construction is scheduled for FY2011.

Additionally, the results of the pressurizing plant condition assessments will be used to prioritize future replacements.

With regard to cathodic protection systems, the cathodic protection for the 230kV pipe-type underground cables #71 and #72 between [redacted] and [redacted] substations in Buffalo was in a deteriorated condition. Upgrades and repairs have been completed for the cathodic protection system on these cables.

Also in Buffalo, the polarization cells on the [redacted] bus tie cable and [redacted] cable are showing signs of deterioration. Projects have been initiated to replace these with solid state isolators.

A class of cathodic protection identified as "rectifier and polarizing resistor" is considered obsolete. National Grid is developing a strategy to replace these cathodic protection systems.

Summary

National Grid has a small population of oil filled and solid dielectric cables. No major condition issues are currently observed however, work on ancillary equipment such as pumping plants and cathodic protection is required in the short-term to preserve the reliability of the cable systems. Without these remedial works the reliability of the cables themselves may be impacted with large consequential costs and long outages for cable repairs.

Right of Way Vegetation Management

National Grid's Vegetation Management Plan (VMP) seeks to minimize outages due to vegetation. Other objectives of the VMP include providing a clear and safe work space and access for maintenance activities.

National Grid's strategic approach to vegetation management within the right-of-way is to establish and maintain right-of-ways that are largely clear of all incompatible vegetation while maintaining a stable low-growing plant community that is pleasing to the eye and beneficial to wildlife. National Grid's strategic approach to manage vegetation adjacent to the right-of-way is to prune and/or remove danger trees and/or hazard trees where property rights allow vegetation management work.

Vegetation management work on transmission and distribution right-of-ways is organized into two programs:

- Right-of-Way Floor Program – management of vegetation within the right-of-way corridor, and
- Off Right-of-Way Danger Tree Program – management of vegetation adjacent to the right-of-way corridor.

To achieve its vegetation management objectives, National Grid utilizes an Integrated Vegetation Management (IVM) approach which emphasizes selective herbicide use to control incompatible vegetation. IVM integrates the use of various methods of herbicide applications and non-herbicide mechanical vegetation management methods, and is used on both the right-of-way floor and the adjacent utility forest. The IVM program includes the use of herbicide (supplied as Basal Application, Stump Application and Foliar Application), Hand Cutting, Mowing, Selective Mowing and Selective Pruning methods.

Floor Program

National Grid's right-of-way floor program is a treatment operation which generally includes most of the vegetation management methods described herein. Herbicide treatments, employing herbicides and treatment methods consistent with the sensitivity of the site, are the preferred method of vegetation management. Four methods of herbicide treatments are utilized: basal application, cut stump application and low-volume and high-volume foliar applications.

Treatment is generally carried out in two phases: Preparatory Treatment and Foliar Treatment. These two phases may be carried out separately or simultaneously depending on vegetative conditions or permit requirements for each right-of-way segment.

An IVM treatment operation is carried out within a treatment/calendar year. Preparatory treatment is generally completed prior to June 1 so that any vegetation approaching the minimum clearance distance is treated prior to new annual growth. Foliar treatments are completed prior to October 1 of each year. National Grid contractors preparatory treat all vegetation approaching the Minimum Clearance Distance prior to June 1 of a treatment year to assure reliability of the line. Cycle lengths for the right-of-way floor program range between five to eight years.

Danger Tree Program

National Grid right-of-ways are generally cleared to their full width consistent with legal real estate rights and/or permits for initial construction of the electric lines. The forested landscape beyond the maintained right-of-way may contain trees tall enough and close enough to electric conductors to be capable of growing or falling into the lines. These trees are classified as danger trees and hazard trees. A danger tree is a tree on or off the right-of-way that if it fell could contact electric lines. A hazard tree is a danger tree which due to species and/or structural defect is likely to fall into the electric facility. National Grid prunes or removes danger trees and hazard trees to reduce the risk of off right-of-way tree-caused outages. Trees are pruned to achieve At Time of Vegetation Management (ATVM) Clearance Distance from vegetation, in a radius around the conductor. Danger tree cycles for transmission and sub-transmission line right-of-ways range from five to 16 years.

National Grid Transmission Forestry staff is responsible for inspection of vegetation conditions on right-of-ways. Inspections are carried out for several purposes including, but not limited to: determination of treatment efficacy of herbicide floor work following work completion by contractors (the Spring following treatment); evaluation of efficacy of floor maintenance cycle length; planning danger tree work and patrolling the transmission system to find vegetation conditions that are an imminent threat to the reliability of the electric system.

Substations

This section will describe the key elements of transmission substations that populate the service territory. Specifically, the inventory and age, condition and performance issues and other information for Circuit Breakers, Disconnects, Transformers, Other Equipment and Substation Rebuilds are discussed.

Circuit Breakers

There are 708 circuit breakers on the National Grid US New York Transmission system. The types of circuit breakers used in the service territory are categorized as gas, oil and vacuum. The greatest majority of circuit breakers in the service territory are in the 115kV range. The following provides a brief summary of each type.

- Gas Circuit Breakers (GCB) - 330 or 47 percent of the service territory's breakers are newer technology GCBs. The population of GCBs are all within their anticipated service life with all but the earliest vintage (1982) in excellent condition.

- Oil Circuit Breakers (OCB) - 377 or about 53 percent of the service territory breakers are older technology OCBs.[29] The average age of oil circuit breakers is 42 years.

[29] Ninety percent, nine percent and one percent of 115kV, 230kV and 345kV circuit breakers respectively

Approximately two percent are greater than 60 years old, 59 percent of the total population of oil circuit breakers is between 40 and 59 years old and 38 percent are 20 to 39 years old.

- Vacuum Circuit Breakers - There is one vacuum breaker in the system.

Figure III-10.
NY Circuit Breaker Age Profile

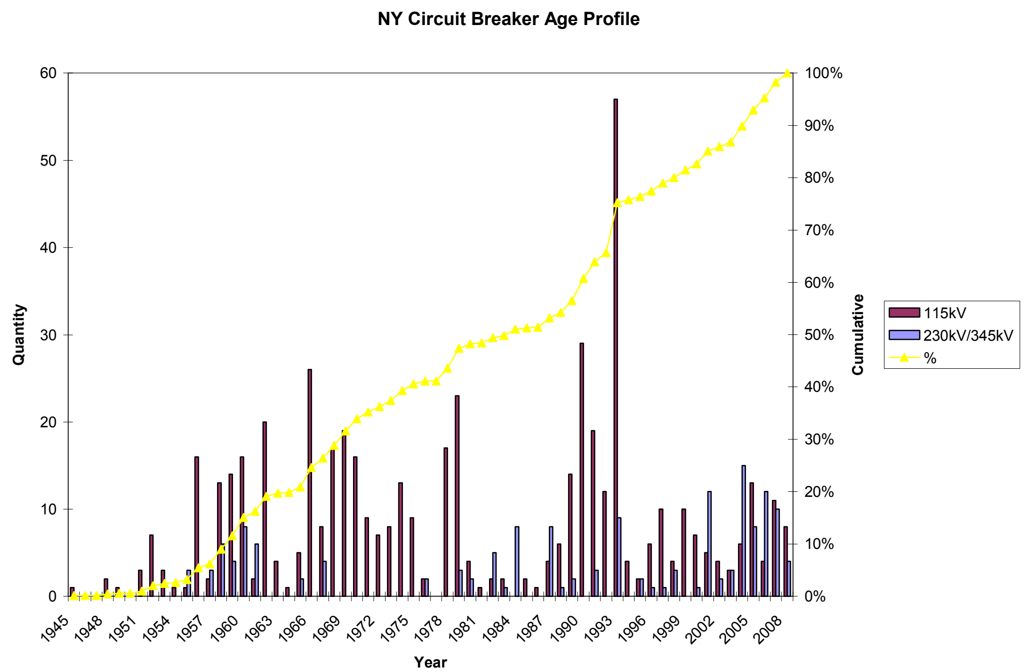


Table III-33
Asset/Age Profile

Asset/ Age Profile (Years)	0-19	20-39	40-59	60+	Total
Circuit Breakers	301	177	223	7	708

Due to the key function carried out by circuit breakers (particularly for fault clearance), these assets cannot be allowed to become unacceptably unreliable. As such, an "operate until it fails" approach is not advocated by National Grid and all circuit breakers should be replaced before the latest onset of significant unreliability. Different deterioration modes and life limiting processes become known as switching devices age. Known deterioration modes and factors that contribute to the end of life for oil circuit breakers include loss of elasticity of gaskets allowing water ingress or oil leakage, frost jacking of porcelain to metal joints, excessive wear of moving parts, corrosion, etc. The anticipated asset life of oil circuit breakers is considered to have been reached when the cumulative effects of the life limiting factors results in unacceptable level of unreliability and repair is either not possible or not economic.

Condition and Performance Issues

Circuit breakers are given a condition code based on manufacturer family and age data. Manufacturer family ratings are based on historical performance of that family. The condition codes are further refined by a visual site survey performed on the specific assets. Circuit breakers are also given a Replacement Priority by applying both technical and specific business criteria (Table III-34). The condition codes define the requirement to replace or refurbish based solely on the condition and performance of the asset while the replacement priorities also include criticality in terms of safety, environmental or reliability consequences of asset failure.

This distinction recognizes that two assets, both with the same condition code, can have a different replacement priority[30] because of the consequence of failure.

Table III-34
Asset/Replacement Priority

Asset/ Replacement Priority	1	2	3	4	Total
Circuit Breakers (2008)	326	114	216	40	696
Circuit Breakers (2009)	480	50	156	22	708

The Company is improving its knowledge of the asset population's condition issues. As a result, the Company has reassessed replacement priority scores for circuit breaker populations and the number of highest priority units for replacement has been reduced. Specific circuit breaker condition and performance issues are detailed below.

The predicted asset life of bulk oil circuit breakers is 45-years with the earliest onset of significant unreliability predicted by age 40. The oil circuit breakers in New York were manufactured and installed over a forty-year period (from 1954 through to 1994) and based upon the known deterioration modes the earliest installed circuit breakers would be expected to be at, or approaching, the end of their asset life. There are approximately 148 (117 of which are 115kV) circuit breakers that have reached their anticipated asset end of life and without future investment this number will increase to 257 (221 of which are 115kV) by the end of 2017. There is evidence of deterioration through known failure mechanisms and in some cases circuit breakers are being kept in service using salvaged second-hand parts from retired equipment. This approach is not considered sustainable and significant asset replacement and refurbishment programs will be required over the coming decade to replace these deteriorated assets

A review of 'follow-up' work orders shows that in the period from January 2005 to September 2009 there were 553 follow-up work orders created on circuit breakers in New

[30] Refer to Report on the Condition of Physical Elements of Transmissions and Distribution Systems- Page III-19, October 1, 2008.

York, of these 333 were associated with OCB (of the remainder, the majority were replenishment of SF6 GCBs). Approximately 63 percent of all the follow-up work orders on OCBs are attributable to just two circuit breakers types, namely the Allis Chalmers Type BZO and the General Electric FK. Overall, there are currently four manufactures of OCBs used in the service territory that are under consideration for replacement due to asset condition and performance issues. These breakers are:

- Federal Pacific RHE 115 & 230kV
- General Electric Type FK & FGK 115, 230 & 345kV
- Westinghouse GM-3, GM-4 & 1150GM 115kV
- Allis Chalmers Type BZO 115 & 230kV

The average age of SF6 Gas Circuit Breakers in New York is approximately 13 years old. However, there are three Westinghouse 362SFA40 SF6 Gas Circuit Breakers (362kV) that are 30 years old (1979) in service at [redacted] Substation and two that are 33 years old (1976) at [redacted] Substation. These are the oldest SF6 breakers in the New York system and suffer from air leaks in the operating mechanism. This contributes to pole discrepancies which have resulted in reported instances of the breakers failing to close. The SF6 gas leakage has been reduced by using normal breaker maintenance on these five Westinghouse breakers. There are no plans to replace these breakers at this time and maintenance will continue to be performed on these breakers to lessen the SF6 gas release to the atmosphere. The last of the [redacted] Substation SF6 circuit breakers will have been rebuilt by the end of the summer of 2009 and this should extend the life of these breakers 15 to 20 years.

- August 2009 - [redacted] - a motor vehicle accident on [redacted] resulted in a telephone line tripping out the 115kV [redacted] line and the [redacted] line. The #6 line tripped and locked out. Approximately 50 seconds later the [redacted] line tripped and reclosed several times before locking out. After the line faults were cleared and the lines patrolled the [redacted] Substation circuit breakers R6 & R7 could not be restored to service. Both circuit breakers were taken out of service and isolated to perform breaker testing. Testing of these two circuit breakers indicated both breakers failed internally. These breakers are ABB type 121PM40's SF6 circuit breakers built in 1991. Internal inspections of the circuit breakers revealed that the interrupters were damaged. It is believed that circuit breaker R6 failed attempting to clear the initial fault and circuit breaker R7 failed attempting to clear the resulting bus fault caused by the failure of circuit breaker R6. National Grid along with the original manufacturers will perform a detailed investigation of these circuit breaker failures to ascertain why the interrupters failed during fault clearing duty.

Remedial Actions Performed and Planned

National Grid has a number of strategies in development and planned for the future that will remove the worst performing oil circuit breakers to improve the reliability of the substations. Specifically, the following circuit breaker replacements are planned over the next 10 years (Table III-35). The scope of works will include where necessary the replacement of circuit breakers along with their associated CTs, PTs, Disconnects and control cabling:

Table III-35.
Circuit Breaker Replacements

Location	Type
[redacted]	FK-439 & BZO-115
	GM-6, FK-439 & BZO
	1150GM10000 & BZO-121
	BZO-115, FK-115 & GM-6
	FK-439 & BZO-115
	GM-6 & FK-439
	FK-239
	RHE-64, FK-115 & GM-6
	FK-439 & FK-115
	BZO-230 & FGK-230
	RHE-84
	GM-6
	BZO-115, BZO-160, FK-439 & GM-5
	AA10, GM-6 & BZO-121
	FK-115 & RHE-64
	FK-115, FK-439 & BZO-115
	GM-6
	FK-439, GM-6 & FK-115
	BZO-115 & GM-6
	FK-115, FK-439 & GO-3A
	2300GW
	2300GW & FGK-230
	FK-439, 2300GW & FK-115
	FGK-345
	GM-6B & FK-115
	GM-6B
	FK-115
	FK-115
	FK-439

As discussed in the 2008 Asset Condition report regarding the issues with air-blast circuit breakers (ABBs), the Company has replaced the last ABBs in the service territory. The ABB breakers at Oswego Switchyard were replaced with SF6 HVB 362 50000 breakers. There are now no ABBs left in the service territory.

Summary

As can be seen from all of the above information the upstate New York Transmission System circuit breaker fleet is mainly (53 percent) made up of older oil circuit breakers and the majority (90 percent) of these OCBs are installed at 115kV. The oil circuit breaker fleet is becoming a high maintenance burden and an increasingly aging asset population that puts system reliability and customer service at risk.

Disconnects

There are 2,442 disconnects in the National Grid service territory.

Condition and Performance Issues

All disconnects are monitored using annual thermo-vision checks (152 performed) and bi-monthly visual inspections (727 performed). Motor mechanisms are also inspected yearly (107 performed).[31]

A number of disconnects were identified as being inoperable, difficult to adjust due to mechanical wear, having manual operating linkage problems, vulnerable to hot spots, or having lubrication problems. Several obsolete motor mechanisms are out of service due to lack of spare parts such as motors and gears needed to repair defects.

However, due to the relatively minor function of disconnects there are no proactive plans for their replacement or refurbishment. A failure to operate is operationally inconvenient but generally poses no system or safety risk. Disconnects will typically be replaced along with their associated circuit breaker (as previously noted).

A description of disconnects with condition issues follows.

- ITE MO-10 Disconnects – 115kV, 230kV, 345kV - There are twenty-six of these disconnects in the Company's New York service territory. These disconnects were installed between 1970 and 1984. The oldest two (1970) are at [redacted] Substation.
  - Nine sets are located at [redacted] Substation – Based on discussions with substation personnel, hot spots have been an issue.
  - The remaining ITE disconnects are at the following New York Substations: four-[redacted] two-[redacted] two-[redacted] three-[redacted] and one each at [redacted] and [redacted].
- General Electric RF-2 Disconnects – 115 & 230kV - Eight sets of GE RF-2 disconnects are currently installed on the 115 & 230 kV bus at [redacted] substation. These were installed in 1962. Several others have required repair using parts from retired switches.
- Haefly-Trench Disconnects- 115kV - Twelve sets of these vertically mounted gang operated switches have had insulator failure at various locations. The insulators are post type and are failing where the porcelain and cap are bonded together.

[31] These tests were performed in July 2009.

- Westinghouse Type V Disconnects -115kV - These disconnects are either inoperable or limited to manual operation at [redacted] Substations. They have experienced motor, gear box, and adjustment problems due to mechanical wear, operating linkage problems, bearing problems due to lubrication issues, and insulators failing due to water ingress and thermal action.
- R&IE Type TTR-49 – 115kV & 230kV - There are six R&IE Type TTR-49 disconnects located in the [redacted] 230kV yard. These disconnects are old and in poor overall condition.
- Flying Ground Switches - This type of switch is primarily utilized in the Western Division (17 switches in service in the Buffalo area & 2 switches in service in the Albany area) as a transformer protective device and is manufactured by Haefely Trench and Delta Star. These switches were installed in the mid to late 1950s. Over time the operating speed of these switches has decreased because of worn linkages and mechanism components. These switches subject the transmission system to a second fault and interrupt more of the system than necessary. The time to operate the ground switch to initiate the line relays to remove the fault increases the amount of time the transformer is subjected to the fault possibly increasing damage to the transformer as well as increasing the likelihood of recordable events. Reopening the ground switch to re-cock after an operation is difficult due to adjustment problems.

Remedial Actions Performed and Planned

- ITE MO-10 Disconnects – 115kV, 230kV, 345kV - These disconnects are monitored through yearly thermo-vision inspections. Problems are fixed individually when identified.
- General Electric RF-2 Disconnects – 115 & 230kV -. The #51 disconnects at [redacted] presently require repair and are being monitored.
- Haefly-Trench Disconnects- 115kV - A condition assessment was performed in August 2008 that will be the basis for a possible replacement project at [redacted] Substations.
- Westinghouse Type V Disconnects -115kV – Generally, any issues on these disconnects are being addressed as they come up. The disconnects at [redacted] and [redacted] will be replaced with upcoming rebuild projects.
- R&IE Type TTR-49 – 115kV & 230kV - Issues with these disconnects are being addressed as they come up.
- Flying Ground Switches - The most problematic switch, at [redacted], is being replaced in 2009. A strategy was approved in August 2009 to replace the remaining flying ground switches.

Summary

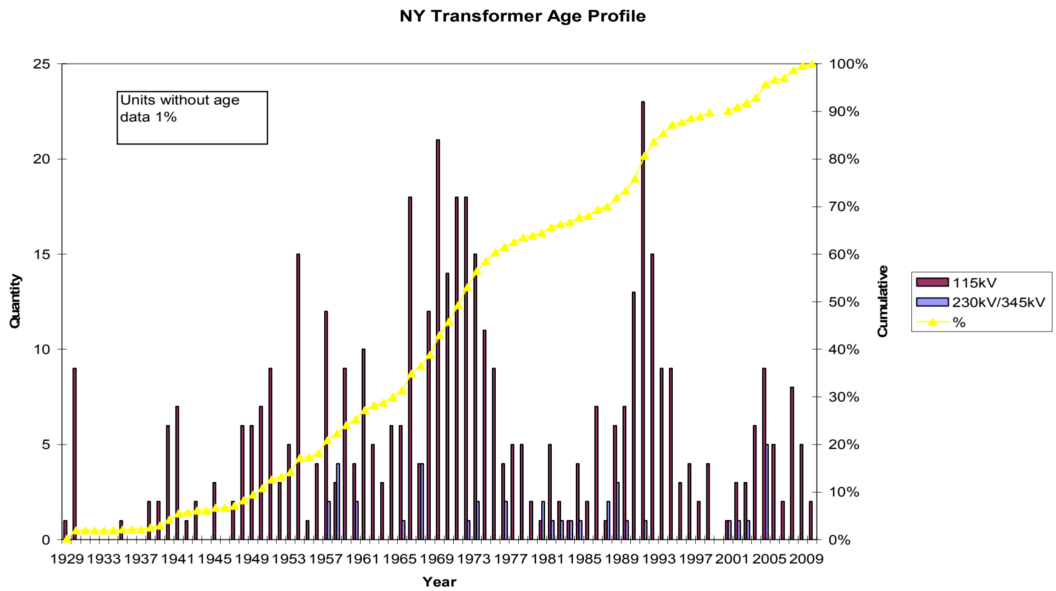
In general Disconnects do not impact reliability. Vertical break disconnects do present a known safety hazard when the older porcelain insulators fail and the disconnect falls towards the operator. The Company will continue to use the “lead asset” approach to identifying replacement candidates and as such disconnects will typically be replaced in conjunction with their associated circuit breakers. If we are unable to replace circuit breakers a safety driven program to replace disconnects may be required.

Flying grounds are no longer considered a suitable method of fault clearance. Not undertaking the replacement of these devices will perpetuate an arrangement that introduces further faults on the transmission system, creates a hazard to personnel and may lead to additional transformer failures.

Transformers

The National Grid New York Transmission System has a transformer population of 508 units of various manufacture, types, and power ratings at voltages greater than 115 kV. An age profile is provided in Figure III-11.

Figure III-11.
NY Transformer Age Profile



Their numbers and ages are shown in Table III-36.[32]

Table III-36.
Asset/Age Profile

Asset/ Age Profile (Years)	0-19	20-39	40-59	60+	Total
Transformers	135	154	170	48	507

Forty-three percent of the total population of transformers is greater than 40 years old and the average age of the transformers on the NY system is 35 years. Transformers installed in the 1950s and 60s are approaching the end of the useful life based on known deterioration modes. By the end of 2009, there will be 78 transformers in New York that will be at or beyond 55 years old. All of these are 115kV units.

[32] Less than one percent is without age data.

By 2017 the number of transformers beyond their useful life will, without investment, rise to 142 in New York. This position is unsustainable and a significant asset replacement program will be required over the coming decade. The replacement program will initially target transformers with known design weaknesses or unusual Dissolved Gas Analysis signatures and then older units at critical locations.

Condition and Performance Issues

Dissolved Gas Analysis (DGA) is the Company's standard, regular and cost effective condition assessment test to detect anomalous behaviors within transformers which may indicate a developing fault. All transmission transformers are sampled at least annually with suspected defective units on enhanced sample intervals. Power factor testing of the transformers and their associated bushings and an assessment of the line tap-changer is performed during routine maintenance. Additional testing such as winding impedance and swept frequency response analysis may be recommended if a review of DGA results indicate that anomalous results need to be investigated further.

The data is aggregated to produce a transformer condition code (1 to 4). These codes are defined in Table III-37.

Table III-37.
Condition Code Description

Condition Code	Description
4	Under active review to identify whether the transformer has an internal problem or whether there is a benign reason for the behavior. Code 4 transformers are recommended for replacement or evaluated and re-coded.
3	Units are suspected of having developing internal problems.
2	Indicates a transformer belonging to a suspected design group; however, there are currently no known issues with this unit.
1	Indicates a normal transformer with no known issues.

In addition to the condition code above, transformers are given a replacement priority by applying both technical and specific business criteria. This year transformer replacement priority score 3 is broken down into (3a and 3b). This refinement provides a better understanding of a transformer's overall health and criticality on the system. 3a transformers are in an age group that industry experience suggests should be replaced in the next three to 10 years. 3b transformers would be candidates for replacement over the next 10 to 15 years.

Table III-38
Asset/Replacement Priority

Asset/ Replacement Priority	**1**	**2**	**3b**	**3a**	**4**	**Total**
Transformers (2009)	140	80	103	154	36	513
Transformers (2008)	350	44	110		16	520

This year, the Company has included all single-phase windings associated with Priority 4 units. Going forward the aim will be to install three-phase transformers in place of three single-phase units. This will reduce the price of transformers through standardization and reduce the number of spares required to support the population.

The priority score in 2008 was largely based on age data. This year the Company has reconsidered the replacement priority of transformers and increased by around 50 the number of units that would be replaced over the next 15 years. Over the next 12 months the Company intends to develop a less subjective methodology for replacement scoring. The revised methodology will take into account DGA scores, engineering judgment and age related information which will be weighted appropriately to provide a consistent scoring methodology. Table III-39 shows the latest transformer condition ranking based on Dissolved Gas Analysis results.

Table III-39.
Dissolved Gas Analysis

Locations	04/10/09 rank	August 2008 rank	June 2008 Rank	March 2008 Rank
[redacted]	#N/A	169	191	197
[redacted]	#N/A	907	926	#N/A
[redacted]	1	1	1	1
[redacted]	2	2	3	5
[redacted]	3	52	52	56
[redacted]	4	4	5	7
[redacted]	5	3	21	12
[redacted]	6	6	10	4
[redacted]	7	7	11	11
[redacted]	8	10	14	3
[redacted]	9	14	699	709
[redacted]	10	#N/A	#N/A	#N/A
[redacted]	11	17	17	17
[redacted]	12	16	16	22
[redacted]	13	13	18	19
[redacted]	14	18	12	13
[redacted]	15	55	56	60
[redacted]	16	49	27	27
[redacted]	17	21	26	25
[redacted]	18	38	39	44
[redacted]	19	22	24	23
[redacted]	20	23	19	18
[redacted]	21	45	45	50
[redacted]	22	25	1059	#N/A
[redacted]	23	311	336	345
[redacted]	24	29	35	39
[redacted]	25	28	973	#N/A
[redacted]	26	11	20	14
[redacted]	27	31	987	#N/A
[redacted]	28	33	57	61
[redacted]	29	35	978	#N/A
[redacted]	30	857	8	433
[redacted]	31	37	49	53
[redacted]	32	34	46	79
[redacted]	33	19	22	45
[redacted]	34	40	40	35
[redacted]	35	43	43	49
[redacted]	36	39	51	55
[redacted]	37	42	41	77
[redacted]	38	47	48	52

The unforeseeable failure rate over the past 18 months for the transformer population was 0.6 percent (three failures). This failure rate is consistent with evidence from a larger IEEE population survey which suggests a typical failure rate of 0.6 percent. Two failed transformers were at the [redacted] and [redacted] Substations, a third unit was replaced at the [redacted] Substation due to DGA results.

The fundamental life-limiting process for transformers is paper ageing, as the paper insulation becomes mechanically brittle, and susceptible to dielectric failure if mechanically disturbed. The rate of aging is mainly dependent upon the temperature and moisture content of the insulation. The paper and pressboard used in the construction of the transformer may shrink with age which can lead to the windings becoming slack. This ultimately compromises the ability of the transformer windings to withstand the electro-magnetic forces generated by faults. There are no cost-effective maintenance practices that can be used to correct the paper aging process although processing the oil may address the moisture content in the short term.

Table III-40 gives the latest information on specific transformer issues identified by substation O &M Services.

Table III-40
Transformer Issues

Substation	Comments
[redacted]	Transformer exhibited high combustible gassing levels in early 1990's. No conclusive results found during extensive diagnostic testing. Unit is being monitored with a Severon on-line gas monitor. There is a higher than normal unexpected failure mode of this design due to T Beam heating and static electrification
[redacted]	McGraw Shell design known as weak. Signs of hot spots developing by DGA key gases
[redacted]	1988: Rebuilt after failure in [redacted] and placed back in service at [redacted] McGraw Shell design known as weak. FOA Cooler replacements to fix oil leaks performed in 2008.
[redacted]	McGraw Shell design known as weak. Signs of hot spots developing by DGA key gases
[redacted]	The transformers are aging normally. The DGA and oil quality are acceptable. The oil is non-pcb. There are a few minor leaks on the transformer; a few coolers have been replaced due to leaks. .here is a higher than normal unexpected failure mode of this design due to T Beam heating and static electrification. There were four in the population, one failed and another is scheduled to be replaced. This transformers has an above normal failure mode. The steel support for the LTC tank is deteriorating and requires replacement or repair. The arrestors require replacement. Spill containment needs to be evaluated.
[redacted]	TB#3 is a 230/120/13.2kV,125 MVA auto-transformer manufactured by GE in 1957. TB#3 has been identified as a poor design at the end of useful life. A GE transformer of this family failed at [redacted] and other units of this design generate moderate to high levels of combustible gas which indicates internal problems. These transformers have an unusual LTC construction that is unique to them making field maintenance impossible. Presently, National Grid is monitoring the heating gases in DGA test results with an online DGA and condition monitoring system via EMS. There is an existing project to replace both TB#3 and TB#4 transformers at [redacted] by the year 2013
[redacted]	TB#4 is a 230/120/13.2kV,125 MVA auto-transformer manufactured by GE in 1957. Issues with this transformer are the same as for [redacted] TB 3.
[redacted]	TB#3 is a 230/120/13.2kV,125 MVA auto-transformer manufactured by GE in 1957. TB#3 has been identified as a poor design at the end of useful life. A GE transformer of this family failed at [redacted] and other units of this design generate moderate to high levels of combustible gas which indicates internal problems. These transformers have an unusual LTC construction that is unique to them making field maintenance impossible. Presently, National Grid is monitoring the heating gases in DGA test results with an online DGA and condition monitoring system via EMS.

Table III-40 (continued)
Transformer Issues

Substation	Comments
[redacted]	TB#4 is a 230/120/13.2kV,125 MVA auto-transformer manufactured by GE in 1957. TB#4 has been identified as a poor design at the end of useful life. A GE transformer of this family failed at [redacted] and other units of this design generate moderate to high levels of combustible gas which indicates internal problems. These transformers have an unusual LTC construction that is unique to them making field maintenance impossible. Presently, National Grid is monitoring the heating gases in DGA test results with an online DGA and condition monitoring system via EMS.
	The DGA exhibits hot spot heating. The oil is non-pcb. There are a few minor leaks on the transformer and a few coolers have been replaced due to leaks. There is a higher than normal unexpected failure mode of this design due to T Beam heating and static electrification. There are two in the population. The arrestors require replacement.
	Bank failed and was rewound not long after initial installation in 1960's. No DGA information is available to properly rate this bank after rebuild. Unit has been loaded heavily in recent years.
	A sister unit failed in 2007 due to center winding insulation breakdown in high stress area of the winding. Bank exhibits gassing levels similar to failed bank
	Tilden station is a major source to the southside of Syracuse and also receives input from a vital generation source (OCCRA). Significant leaks, gasketing , tank issues
	The 'A' phase unit shows signs of gassing, all units have leaks and significant rust. Provides 34.5kV power to fossil generating station as well as our own sub-transmission loop
	Bank shows significant signs of heating gasses. Average physical condition for age with some weeping
	Sister unit to the 3-A unit, operated in parallel to make one bank. Average physical condition for age with some weeping
	Sister unit failed in January 2008. Unit has seen numerous documented through faults. Electrical tests satisfactory. The two banks at McIntyre are the only feeds to that areas 23kV system supporting 5000 customers.
	Unit 4A-C 115-34-13kV is PCB contaminated. Spill containment is damaged and needs to be repaired

Remedial Actions Performed and Planned

Table III-41 provides a list of transformers that are currently proposed for replacement over the next 10 years, based on condition scores and replacement priority. However, there may be transformers which deteriorate from condition 1 to 4 very rapidly. Constant surveillance and regular DGA sampling will enable the Company to prioritize replacement appropriately.

Table III-41.
Ten Year Proposed Transformer Replacement

Station and Transformer Number	Replacement Priority
[redacted]	4
[redacted]	4
[redacted]	3a
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
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[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4
[redacted]	4

Summary

By 2017 the number of transformers beyond their useful life will, without investment, rise to 142 in New York. This position is unsustainable and a significant asset replacement program will be implemented over the coming decade. The replacement program will target transformers with known design weaknesses or unusual DGA initially and, afterwards, older units at critical locations.

The failure to implement a transformer replacement program will lead to greater number of failures that will impact customer supply. If a more reactionary asset management approach is adopted the Company will need to purchase additional strategic spare transformers to manage the failures. The failure in service of a large power transformer can have significant operational and safety impacts especially where a tank breach and oil fire is concerned.

Other Equipment

This section will discuss lesser system components such as Battery Systems, Surge Arrestors, Relays, Digital Fault Recorders, and Circuit Switches.

Battery Systems

Battery and charger systems provide the power to charge breaker coils which allow the breaker to operate successfully. National Grid has recently proposed a battery replacement policy. This policy proposes the replacement of all battery sets that are 20 years old or if battery conditions dictate as per National Grid Substation Maintenance Standards. The 20 year asset life is based on industry best practice and our experience in managing battery systems. There are, at present, approximately 260 battery sets installed, 15 known to be in excess of 20 years, 71 battery sets will be over 20 years old between 2009 and 2014 (Figures III-12, 13 and Table III-43 and 44). To address this aging population, an asset replacement program will be implemented over the next 10 years.

Currently, the Company is concerned about systems in substations that are located in the control buildings of divested generation. The new generation owners control access and maintenance to these facilities. A strategy to consider asset separation is being assessed by National Grid.

Figure III-12
Battery Age Profile

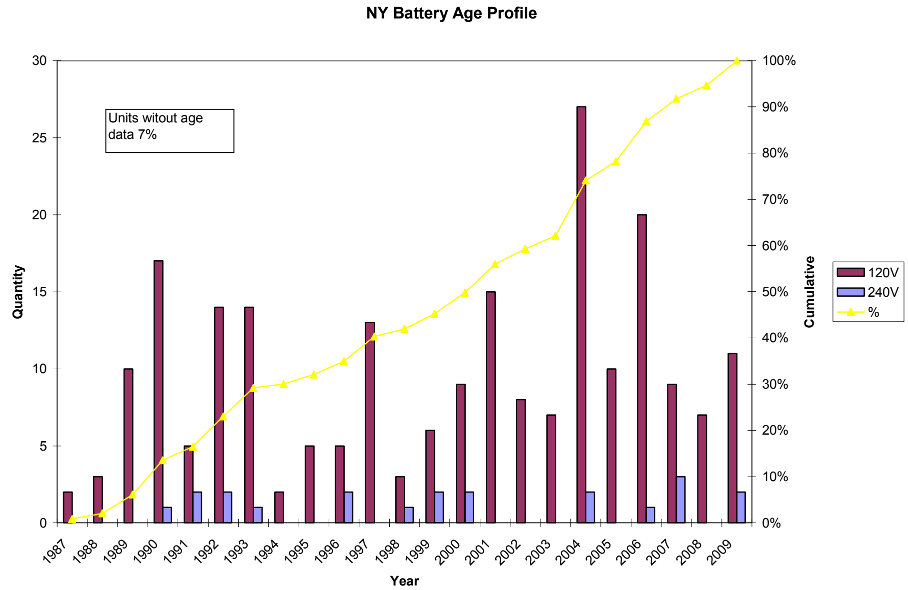


Figure III-13:
Charger Age Profile

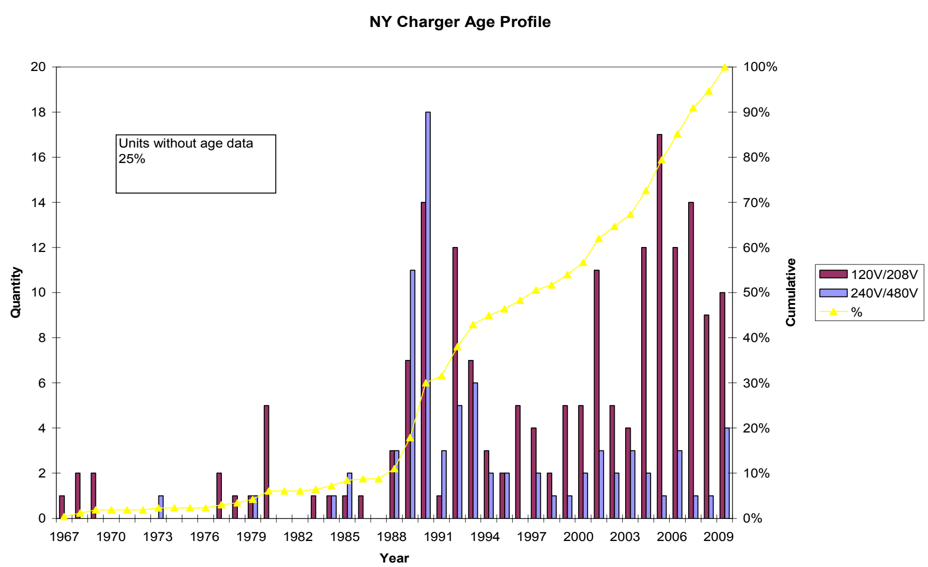


Table III-43.
Asset/Age Profile

Asset/ Age Profile (Years)	0-4	5-9	10-14	15-19	20+	Total
Batteries[33]	63	70	37	58	15	243
Chargers[34]	72	49	24	71	47	263

Table III-44.
Asset/Replacement Priority

Asset/ Replacement Priority	1	2	3	4	Total
Batteries[35]	134	22	17	86	259

Remedial Actions Performed

As of July 2009, National Grid US Transmission O&M Services has performed 84 inspections of battery and charger sets. The Company also performed all of its battery maintenance on its Bulk Power Stations as per NPCC/NERC battery station requirements.

Summary

The requirement for a safe and reliable DC system is paramount. Not adopting a planned replacement approach for battery systems will in the longer-term lead to failures to trip and extended duration faults on the power system with the consequential likelihood of system instability.

Surge Arrestors

There are 691 surge arresters at 115kV and above installed in the service territory. However installation dates are largely incomplete as surge arresters were classified as part of transformer installation. Information from O&M Services suggests that up to 79 percent of surge arrestors are silicon carbide (SiC) type with a large volume estimated to be over thirty years-old.

Condition and Performance Issues

Due to the age and technology, the SiC surge arrestors may no longer be effective. SiC gapped surge arrestors were manufactured and installed up to the mid 1980s. The technology is based on non-linear SiC resistors with a series controlled spark gap. The spark gap is in a

[33] Batteries without age data is 17
[34] Chargers without age data is 86
[35] Less than one percent is without age replacement data.

controlled environment and provides the trigger to activate the arrestors into operation. Although effective, this design is now obsolete and no longer manufactured due to developments in technology. Metal oxide gap-less surge arrestors have replaced the SiC resistors and are now the preferred method to control lightning and switching over-voltages.

National Grid experiences on average three surge arrester failures each year and the vast majority of these surge arrester failures are silicon carbide type. Currently, the lifetime of a silicon carbide surge arrestor is anticipated by National Grid to be approximately 20 to 25 years. The integrity of SiC beyond this time frame cannot be guaranteed due to concerns over pollution performance, poor mechanical reliability (e.g. poor seals, internal corrosion, etc.) and difficulty of monitoring the condition of the series gaps. Industry sources recommend that all silicon carbide arresters in service over 13 years be replaced due to moisture ingress. Manufacturer's data suggests that moisture ingress is the direct cause of failure in 86 percent of failures.

Remedial Actions Performed and Planned

SiC surge arrestors will be replaced during planned maintenance activities on transformers. This is a more efficient program but requires toleration of SiC failure risk for longer periods of time. We reviewed programmatic replacement of SiC surge arresters but concluded that this approach is not practical or efficient. Surge arresters are co-located with their associated transformer and outage constraints would make the planned proactive replacement extremely difficult.

Relays

National Grid maintains three different relay types on its system for protection and control. They are Electromechanical, Solid State and Microprocessor designs. There are approximately 8,000 individual protection relays on the transmission system.[36] The table below identifies the number of relays by type currently deployed on the transmission system.

Table III-45.
Count of relays by type

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

While National Grid does not have complete relay age information in its databases, the electromechanical relays are of a 1970's vintage or older although they were still being installed into the 1980's. Based on the design of the relay, over time, they are subject to a

[36] Last year's report reflected electromechanical relays only (approximately 6,000). This year solid state and microprocessor relays are also included.

variety of environmental factors that can affect their operational characteristics and therefore their lifespan. Solid state relays are also affected by environmental conditions, namely heat. The high temperatures and temperature cycling of control houses greatly shorten their lifespan. Solid state relays are also very susceptible to component failure due to material decomposition, such as resistors and capacitors. In some cases, repairs can be made, but often entire solid state boards must be replaced if they are available. Microprocessor relays are designed to cope better with environmental factors. However, there are known cases of hardware failures. Solid state relays have also reached the end of their life cycle more rapidly than electromechanical relays due to their anticipated shorter service life. Note that power supplies and rotating storage media have also been identified as failure items in digital devices.

Condition and Performance Issues

The inspection results continue to validate our assessment that certain relay families are at or nearing their end-of-life. National Grid performs periodic testing of each protective relay type to ensure that the relay operates correctly and the overall protection scheme functions as designed. Test intervals and maintenance criteria are based on the Northeast Power Coordinating Council's (NPCC) Directory #3 and National Grid's procedure, PR.10.03.002 - Protective Relay Maintenance and Testing, as well as, National Grid's Testing Guideline GL.10.03.001. For example, on Bulk Power lines (mandated by NPCC) microprocessor protective relays are tested every six years, while electromechanical and solid state protective relays are tested and calibrated every four years. For less critical circuits, not covered by NPCC Criteria, microprocessor relays are tested every eight years, while electromechanical and solid state relays are tested and calibrated every four years. In addition to calibration and inspection of protective relays, communication media such as leased lines, power line carrier and fiber are tested annually.

Since last year's filing, over 35 percent of the total relay packages were tested based on their respective scheduled maintenance interval.[37] The testing included a mixture of electromechanical, solid state and microprocessor relays. Issues identified while testing the relays include worn contacts, frayed insulation of wiring due to heat and reduced mechanical strength of electromechanical relays. Calibration drift was also found in electromechanical and solid state relays, indicating electrical/mechanical component failures (i.e. capacitors, coils, resistors). In solid state relays, there are problems with card failures due to heat and age. The test results would show values out of their tolerance window. It is more difficult to fix solid state relays as they are made of discrete components. The lack of spare parts makes it difficult to support these relays. At present, microprocessor relays can be easily replaced on failure as all manufacturers still support them and have spares and replacements readily available.

Some of the existing pilot protection schemes for transmission lines utilize Power Line Carrier (PLC) signaling equipment for relay communications, including analog

[37] For each line or apparatus, there are two protective relay packages (primary and secondary protection). Testing of reclosing, timer, fault detection and/or breaker failure relays would be included with one of the protective relay packages.

transmitter/receiver carrier sets, line traps, Capacitive Coupled Voltage Transformers (CCVT), and tuning units. These communication components require costly periodic testing and maintenance. PLC based protection signaling equipment requires increasing maintenance costs and are prone to more frequent failures due to the aging factors.

Currently, relays are replaced based upon condition and performance issues. This resulted in the replacement of approximately 60 relays last year. For a population of 8,000 relays, replacing on the order of 100 per year would result in a complete turnover every 80 years, well beyond the life expectancy of electromechanical relays. At this replacement rate, a significant number of relays would remain in service 60 to 90 years which may cause degradations in reliability performance. In addition, some of the earlier solid-state relays may need to be planned for replacement during this period (assuming an asset life of 15 to 20 years). In some cases the replacement age could be extended if the total picture of condition and performance can be better understood.

National Grid is developing an asset health review for protection systems to prioritize replacement. The review will identify which relay types are problematic, obsolete and/or no longer supported by the manufacturer. Most of the relays in this group are vintage electromechanical relays and solid state relays. National Grid estimates that approximately 10 percent38 of electromechanical and solid state protective relays on the transmission system need replacement in the near future. These relays are at or near the end of their useful life and replacement parts are not readily available, making continued maintenance of these devices very difficult. The ability to acquire spare parts from previously failed units or outside sources is diminishing with time.

The Company has a robust telecommunications infrastructure in place to support teleprotection systems for remote tripping of the transmission protection systems. The communications infrastructure is currently provided by a mix of internal and external facilities. Internally, we use private fiber and microwave systems while we also use third party (e.g. Verizon) leased lines. These systems are often old analog communication channels that will need to be upgraded to digital to take advantage of the newer protection and control devices.

Remedial Actions Performed and Planned

Since the 2008 Asset Condition report, National Grid has inspected and performed maintenance on 991 relay packages and replaced 60 relays on the transmission system. As noted above, the majority of the inspections of electromechanical relays required additional time for calibration, compared to solid state or micro-processor relays, as they need to be re-adjusted due to moving parts and contact wear. Solid state relays tend to fail due to overheated thyristor and mechanical fatigue in the power semi-conductor circuitry caused by thermal cycling.

[38] Calculated by dividing 656 total relays from Table 2 by 6527 (electromechanical and solid state) relays in Table 1

As noted earlier, National Grid initiated a study to identify the worst performing relay families. These families include electro-mechanical (e/m) and solid-state relays. The study will identify those relays that may be contributing to poor system reliability due to relay mis-operation or non-operation. Thus far, certain families of relays have been identified to either have poor reliability or are considered obsolete such that technical support and spare parts are no longer available from the manufacturer.

The table below summarizes twenty-three families that are under consideration for replacement sorted by priority

Table III-46
Relay Families and Counts to be Replaced by Priority

Relay Design	Relay Family	Relay Type	Number of Relays on system
Electromechanical	G.E. GCX13	Distance Protection	21
Electromechanical	G.E. CEY14	Distance Protection	3
Electromechanical	G.E. CEY15	Distance Protection	99
Electromechanical	G.E. CEY16	Distance Protection	96
Electromechanical	G.E. GCX17	Distance Protection	222
Microprocessor	ABB- MDAR	Distance Protection	9
Electromechanical	G.E.GCY12	Distance Protection	27
Electromechanical	G.E.GCY13	Distance Protection	24
Solid State	RFL Electronics-3253	Distance Protection	15
Solid State	RFL Electronics-6710	Distance Protection	6
Solid State	ASEA- RAZFE	Line Protection	9
Solid State	WESTINGHOUSE-SBFU	Distance Protection	6
Solid State	WESTINGHOUSE-SDGU	Distance Protection	4
Solid State	WESTINGHOUSE- SKDU	Distance Protection	4
Microprocessor	ABB-REL302	Distance Protection	6
Electromechanical	WESTINGHOUSE-HCB	Pilot Wire Differential Protection	5
Solid State	RFL Electronics -6745	Distance Protection	11
Microprocessor	GEC ALSTOM- Optimho	Distance Protection	5
Electromechanical	GE.CEB12	Distance Protection	45
Solid State	GE - TYPE 40	Distance Protection	2
Solid State	G.E.- CS28A	Distance Protection	1
Electromechanical	G.E.-CFD	Differential Protection	6
Electromechanical	G.E.-CPD	Pilot Wire Differential Protection	30
	Total		656

The Company has determined that it will be necessary to establish an accelerated relay replacement program to ensure that system reliability is not diminished due to an inordinate number of relays reaching their end-of-life at the same relative time.

The plan will utilize the table above and develop a process to address the replacement of these relays first. The relays identified above will be replaced under an accelerated program in addition to maintaining the replacement of those relays under the normal replacement cycle.

For the medium term (next two to five years), the relay types and the associated relay packages to be replaced will be identified on the following factors:

- Feedback on performance from the field work force and information on obsolescence received from manufacturers
- Higher priority packages that need to be addressed immediately. The priority criteria will be based on the installation location, failure mode, and risk to system, reliability, customer impact, etc.
- Relays for some specific circuits or equipment with operating issues and relaying problems

Generally, the replacement plan will be implemented on a line-by-line basis. When replacements are being considered at a Bulk Power Station, NPCC A5 Criteria must be followed, which may trigger a complete control room replacement. In some existing stations, a new control room may be required if the control room is in bad condition or can not meet the present requirements; such as limited space available for future expansion and new panels, not meeting fire protection and security code, structural infirmity, poor HVAC performance for relays, etc. Therefore, all the relay packages installed in the old control room will be updated and replaced.

In the longer term, there will be two categories of replacements, one for relay packages only and another for the whole control room. The relay package upgrade will be conducted within the existing control building. The relay package for a particular line or equipment will be identified and the scope of work will be defined carefully to minimize the impact on the operational system. The new protection panel will be designed so as to fit into the position of old panel. During a planned outage, the old protection panels will be removed from their location to avoid confusion and new panel will be installed.

National Grid also has plans underway to review and recommended upgrades to its communications infrastructure supporting the teleprotection of its transmission system. There is currently a heavy reliance on third party leased lines. However, the costs and lead-times associated with further deployments of these lines is problematic. Due to the possibility of fault current being induced onto the third party leased lines in substations, the Company must install costly protection devices. In addition to their costs, the lead-time associated with ordering the protection devices is long. As an alternative, the Company will investigate upgrading its internal communications infrastructure to support digital technologies for teleprotection as well as other applications. The upgrades may result in new fiber and microwave deployments in addition to the leasing of fiber strands or capacity in existing infrastructure.

Summary

National Grid's protection and control systems date back many years and certain aspects of the system are showing its age. With the advent of digital technologies, the Company can upgrade its facilities resulting in greater capability and increased reliability. The Company's first priority is to identify the worst performers and establish the appropriate remedial action. Secondly, the Company is reviewing solutions that enable the "smartgrid" with interoperability and increased insight into the stability of the electric transmission system.

Digital multifunction relays are an ideal choice for a cost-effective method to implement the transmission system protection. The upgrading of old protection systems with digital relays can offer the following features and benefits:

- Digital relays have proven good quality and high availability.
- Improved sensitivity. The executing or comparator component of old relays can only be operated at certain levels.
- A Digital relay which replaces multiple discrete relays results in reduced CT secondary burdens.
- Greater protection and control functionality, self monitoring and the ability to record oscillographic information and Sequence of Events.
- Easy integration to the Distributed Control System via network communications.
- Lower maintenance costs.

By replacing electromechanical and early generation solid state & microprocessor protection relays with technologically advanced integrated digital relays, performance, functionality and maintenance issues should see significant improvement.

Digital Fault Recorders (DFR)

National Grid currently has 20 digital fault recorders deployed that capture and store data from the power system during times of instability or system anomalies. The data is then downloaded to perform post-event analysis. The analysis yields detailed information about the state of the system before, during and after the event. Because of their benefits in understanding system incidents the company has a strategy to increase the use of digital fault recorders on the system. Since 2004 the company has added 11 new DFRs and replaced 2 of the existing units. The current plan is to replace the seven older DFRs and add five new DFRs to our system. At the end of the strategy there would be 25 digital fault recorders deployed throughout the service territory.

Condition and Performance Issues

There have been no performance issued to date however as noted above, the older DFRs are requiring more maintenance. At this time, the newer digital fault recorders have experienced good reliability. The newer units do not have sufficient data to project long term reliability of these devices but we would expect them to have approximately the same reliability as microprocessor relays since they are built on the same platform. We are experiencing increased maintenance on the seven older DFRs due to age related condition issues. These devices are based on an older platform and have spinning disk drives for storage.

Currently, National Grid has determined it is not necessary to commit resources on inspecting these devices. The company has a program to routinely call the units and this ensures that the devices are functioning properly. If we cannot communicate with a DFR, technicians are dispatched to investigate why the DFR is not responding. DFR data is currently used only after-the-fact to investigate system anomalies; DFR's are not critical to system stability and have no reliability impact.

As DFR's are not connected to any control devices, a failure will have no direct impact to system reliability. In the event there is a system anomaly and a DFR is not functional, it may be possible to determine the cause and source of some events by using data from recorders at remote locations.

Remedial Actions Performed and Planned

As part of the Federal Economic Stimulus package, National Grid has applied, in collaboration with NYISO and the other Transmission Owners in the state, for federal funding to cover up to 50 percent of the cost of deployments for up to 12 Phasor Measurement Units (PMU) that can provide a visualization of transmission system stability. The PMU devices can be easily added to the newer DFRs units at minimal cost. The newer DFRs come already configured to accept a PMU upgrade.

At this time, the fleet of DFRs is in good operating condition and need no further action. Should the NYISO and National Grid collaborative application to the Department of Energy be awarded to us, then we would initiate a two-year deployment of up to 12 PMUs. We expect to upgrade 11 DFRs with additional circuitry to deliver PMU data and add one additional stand-alone PMU.

A strategy to install digital fault recorders on non-bulk stations is currently being reconsidered. This strategy was rejected in 2008 but declining reliability in some parts of the 115kV system suggest that targeted deployment of digital fault recorders may provide valuable post-fault information required to ascertain the cause of the outage.

Summary

The collection of digital fault information will increase the ability to identify the location and nature of system failures. The data can help engineers understand the waveforms of specific types of system events and use that knowledge to help categorize failures that would otherwise be unknown. The DFR data can also help determine the location of a system event so that respondents can more quickly respond to the area to identify failed or damaged equipment.

Circuit Switchers

The last remaining S&C Series 2000 Capacitor Switch on the system failed in May 2008. This was replaced with a new circuit switch consequently, there are no S&C Series 2000 circuit switches left in the upstate New York transmission system.

There are seventy S&C Type G and Mark II circuit switches in-service in upstate New York. In 2001 S&C Electric Company discontinued replacement component support for Type G and Mark II models. There is a lack of spare parts for these switches and operational problems are being experienced in the system. In 2008, there were ninety-one S&C Circuit Switchers in-service in New York, twenty-one have since been replaced with new switches with seventy remaining to be replaced. These switches are planned for replacement and are being replaced either during a damage failure incident or as substation equipment is being upgraded during outages. The replacement of a circuit switcher generally requires the bus be switched out to isolate the circuit switcher because typically there is no disconnect between the bus and the circuit switcher. The consequences of not doing this work will be higher operation and maintenance costs as well as higher replacement costs done under damage failure as opposed to a planned and scheduled replacement program.

Station Rebuilds

As reported in the 2008 Asset Condition report, a few transmission substations have significant issues including obsolete design, obsolete equipment, reliability concerns, aged equipment beyond its' predicted service life or equipment that has been under-performing. The following provides a detailed discussion of these projects.

[redacted]

[redacted]

[redacted]

Table III-47.
Outage Information – 230kV

COMPONENT	DATE	NOTE
[redacted]	10/3/05	Line #74 opened at [redacted] end only when [redacted] cleared. Buffalo Relay Department found wiring problems in the CT circuit for TB#31
	5/16/06	[redacted] bus cleared. Bus 30 cleared due to several circuit grounds due to bad wiring.
	5/19/06	[redacted] cleared resulting in the outage. The cause of the bus clearing was a ground on the CT wiring for bus-tie breaker R1312

Table III-48.
Outage Information – 115kV

COMPONENT	DATE	NOTE
[redacted]	10/19/06	CB R252 opened; reclosed manually. The cause of the bus clearing was an error made by the technicians working for NRG (generator) who were conducting the testing

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

B. Sub-Transmission System

This section provides details about National Grid's sub-transmission asset condition. Elements of the system include overhead and underground segments each with various types of asset classes.[39] The system has on-going inspection and maintenance activities which generate information about the state of the assets, in particular the overhead lines, but also has information generated from the recent helicopter survey, which is providing a valuable means of prioritizing lines for condition based intervention: maintenance, refurbishment and replacement.[40] Table III-49 gives a summary of the key overhead and underground sub-transmission assets.

Table III-49
Sub-Transmission Asset Types and Inventory

Sub Transmission Main Assets	Inventory
Towers / Poles	64,400
Line Circuit Miles	3,400 miles
Cable Circuit Miles	1,100 miles

The difference between these figures and the numbers contained in last year's report are due to improvements made in the analysis of assets based on a helicopter survey of overhead lines and local inspections which have provided the Company with better knowledge of the sub-transmission asset base.

National Grid has many sub-transmission assets which are at an age which exceeds their original design life of between 40 and 60 years. The towers/poles on the sub-transmission system have an average age of approximately 42 years. Approximately one third of sub-transmission underground cables are greater than 60 years of age. National Grid is developing project scopes to replace underground cables using age as an indicator, but driven by condition and performance. National Grid's strategic approach to managing its aging sub-transmission assets in New York applies a proactive asset management approach described in last year's report. With respect to sub-transmission, we adopted new inspection and testing methods to be applied to cables both on and off line.

[39] The discussion in this chapter is limited to overhead and underground line assets; substation assets defined as subtransmission are covered in a separate chapter.
[40] The Inspection and Maintenance (I&M) strategy is the primary means of assessing, collecting and addressing issues on the overhead and underground electric system. The I&M program allows the Company to assess the condition of distribution and sub-transmission assets to structure a proactive replacement plan for each asset. Ultimately, the I&M will create a higher level of discipline in maintaining system components that do not need immediate replacement. Most importantly, the beneficial impact on the safety and reliability of the system will be discernible by customers because the operating integrity will be raised and maintained at a relatively high level.

Overhead Lines

As indicated in last year's report, National Grid commissioned a comprehensive helicopter survey of its New York sub-transmission system to improve our knowledge of the assets and update existing data bases. This survey flew over 3,200 circuit miles of the sub transmission network, which constitutes approximately 94 percent of the total system miles. This survey has largely been completed, except for some sections which were not identified to the survey company and some sections which have been retired in place. The survey was undertaken to address several concerns.

- Reliability data indicated that the condition of assets may contribute to an increasing percentage of system outages.
- National Grid decided to digitize its asset records with a complete survey since the primary source of asset data was paper maps.
- National Grid decided to improve its knowledge through a fast inspection method. Field inspections would delay rapid improvement in knowledge as the physical act of in-person field inspections takes considerable time, particularly to remote areas of the system.

The helicopter survey provided a full visual inspection of the sub-transmission assets and associated right-of-way corridors, reports of damaged and deteriorating assets, high resolution imagery of each structure, and geo-referenced digital records of the system for inclusion into the corporate Geographic Information System (GIS).

The helicopter surveys have reported the following number of overhead line assets in Table III-50.

Table III-50
Helicopter Survey Results

Asset	Inventory
Steel Lattice Towers	3,771
Wood Poles	59,766
Steel Poles	98
Unknown Type[41]	723
Total	**64,358**

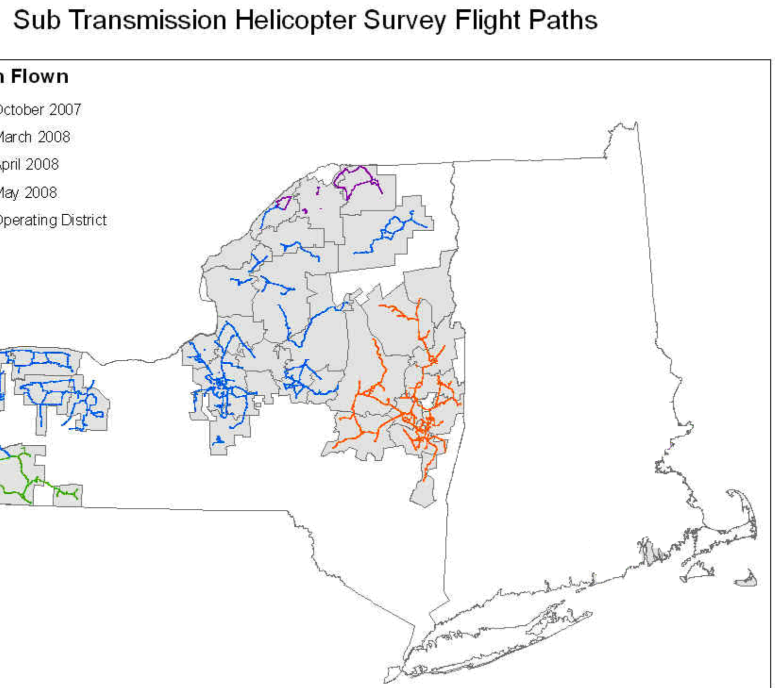
National Grid is currently reviewing options to capture data from the areas not covered by the aerial survey, which consists of approximately 200 miles of the sub-transmission network.

[41] Type of tower structure cannot be determined from helicopter survey. These structures will need to be manually validated.

Condition and Performance Issues

Figure III-19 shows the sections of sub-transmission overhead line surveyed by helicopter. An initial analysis of the survey data was performed in order to develop structural reports and encroachment reports, and identify those stretches of overhead lines with the highest incidence of reports. The reports themselves include both condition information – relating to the physical structures as viewed from the helicopter – and environmental information, relating to trees or other items which may encroach on the rights of way. Ongoing analysis is being conducted by local field staff and asset strategists in an attempt to extract more value from the data.

Figure III-19
Survey Flight Paths



The analysis performed was based on two dimensions:

- total number of reports generated for condition, for encroachment and combined
- number of reports generated per mile for condition, for encroachment and combined

This approach gives an indication of which lines are most in need of attention, and what the overall level of work required.

An individual line may have up to:

- 81 inspection reports
- 219 encroachment reports

- 227 total reports
- An equivalent of 62 reports per mile for lines of at least 0.5 miles in length.

Almost 9,000 separate reports were developed, with almost 6,000 being encroachments.[42]

As a result of the initial analysis and the resulting inspection and encroachment reports, Table III-51 summarizes circuits identified as requiring attention. This list will be refined based on local knowledge of engineers and results of inspection and maintenance activity.

Table III-51
Summary of Poor Performing Circuits based on Inspection and Encroachment Reports

Division	Line Name	kV	Line Length/ miles	Condition Reports	Encroachment Reports	Total Reports	Total Report s/mile
East	[redacted]	34.5	9.4	32	24	56	6.0
East	[redacted]	34.5	30.1	111	58	169	5.6
East	[redacted]	34.5	4.8	25	3	28	5.8
Central	[redacted]	23	0.3	0	1	1	3.3
Central	[redacted]	34.5	2.0	15	14	29	14.5
West	[redacted]	34.5	16.2	91	20	111	6.9
West	[redacted]	34.5	20.5	7	34	41	2.0
Central	[redacted]	34.5	15.9	5	72	77	4.8
East	[redacted]	34.5	3.8	25	16	41	10.8
West	[redacted]	34.5	6.8	7	4	11	1.6
Central	[redacted]	23	3.4	1	6	7	2.1
West	[redacted]	34.5	14.8	44	41	85	5.7
East	[redacted]	34.5	3.3	22	3	25	7.6
East	[redacted]	34.5	2.5	16	4	20	8.0
Central	[redacted]	34.5	16.8	4	20	24	1.4
West	[redacted]	34.5	24.7	27	129	156	6.3
East	[redacted]	34.5	6.7	60	7	67	10.0
Central	[redacted]	34.5	1.5	16	57	73	48.7
Central	[redacted]	34.5	0.8	1	15	16	20.0
West	[redacted]	23	6.8	2	104	106	15.6

42 The helicopter survey included some lines which are retired in place or no longer in service; these may have some significant encroachments.

Further analysis of both inspection report and encroachment report data is in progress to prioritize remedial work through both vegetation management and the Inspection and Maintenance Program. These circuits will then be incorporated into the work plan and used to reprioritize work on the overhead system.

Table III-52 summarizes inspection results based on the additional ground patrol and infrared inspections performed as part of the Inspection and Maintenance Program, Exhibit 5 provides the details of the 2009 inspection findings.

Table III-52
Sub-Transmission Line Inspection Results[43]

Level	Number of Assets Inspected	Work Completed as a Result of Inspections	Percentage of Level Code Completed
2008 Summary (including data between 9/4/08 and 11/30/08)			
1	4	4	100%
2	133	79	59%
3	1010	84	8%
Total	1147	167	15%
2009 Progress to Date (8/10/09) (15,382 structures inspected year to date)			
1	20	20	100%
2	62	10	16%
3	985	6	1%
Total	1067	36	3%

Steel Towers and Steel Poles

There are nearly 3,800 sub-transmission steel structures, most of which are 60 to 90 years old. Towers will normally be refurbished in a timely manner rather than planned for replacement. This will minimize both the costs and outage requirements. However, there comes a point at which so many steel bars require changing that it is more economic to replace the whole tower. Alternatively the end of a tower's useful life may result because is no longer safe to work on the tower.

The visual grading system originally developed for transmission structures is also used for sub-transmission towers.

[43] Asset inspection includes both wood and steel structures/poles.

Table III-53
Sub-Transmission Tower Inspection Results[44]

Level	Arms Damaged	Loose Bolts/Hard	Structure Damage	Tower Legs Broken	Total	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)						
1	1	1	0	0	2	100%
2	0	0	0	0	0	100%
3	0	0	1	0	1	0%
2009 Progress to Date (8/10/09) (436 towers inspected year to date)						
1	0	0	0	0	0	100%
2	0	0	2	1	3	0%
3	0	1	0	0	1	0%

Wood Poles

Interruptions caused by pole related issues are not significant as most pole problems are safety and environment related. While the Company has not experienced a large number of pole failures, National Grid plans to maintain or improve pole age profile in order to mitigate any possible future failure rate increases.

Poles are replaced based on condition as identified through the inspection and maintenance process described above. The results of these inspections performed since last year's report are set forth in Tables III-54, 55, and 56 below.

[44] Assets inspected includes Steel structures and poles.

Table III-54
Sub-Transmission Wood Pole Inspection Results

Level	Number of Poles*	Percent Codes vs. Inspections	Percent Completed
2008 Summary (including data between 9/4/08 and 11/30/08)			
Acceptable Condition	9,379	92.86%	
1	1	0.01%	100%
2	68	0.67%	65%
3	652	6.46%	10%
Total	10,100	100.00%	
2009 Progress to Date (8/10/09)			
Acceptable Condition	14,409	96.41%	
1	0	0.00%	100%
2	28	0.19%	17%
3	509	3.41%	1%
Total	14,946	100.00%	
*These numbers reflect priority codes against poles; individual poles may have more than one code against it.			

Table III-55
Sub-Transmission Crossarm & Brace/Pins Inspection Results

	Crossarms		Braces and Pins	
Level	Number of Assets	Percent Codes Completed	Number of Assets	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)				
Acceptable Condition	-	-	-	-
1	0	0%	0	0%
2	7	100%	10	80%
3	22	9%	37	8%
Total	29		47	
2009 Progress to Date (8/10/09)				
Acceptable Condition	-	-	-	-
1	2	100%	0	0%
2	7	0%	8	38%
3	27	0%	49	0%
Total	36		57	

Table III-56
Sub-Transmission Guys & Anchors Inspection Results

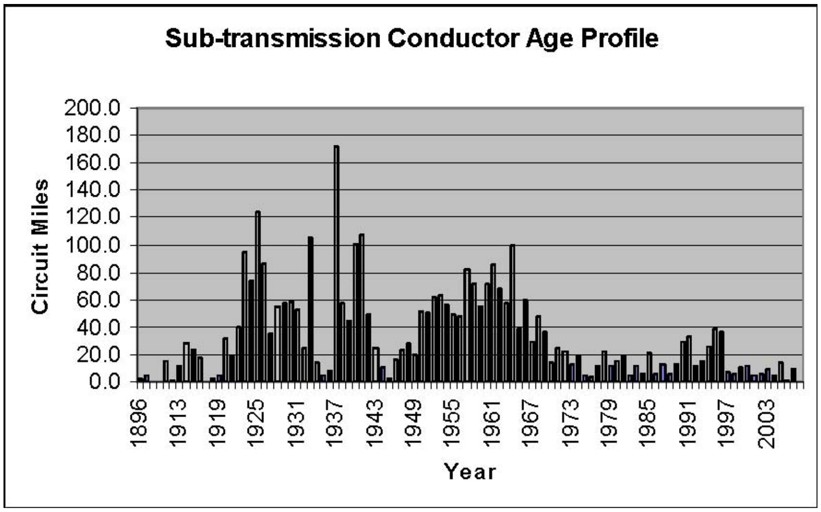
	Guys		Anchors	
Level	**Number of Assets**	**Percent Codes Completed**	**Number of Assets**	**Percent Codes Completed**
2008 Summary (including data between 9/4/08 and 11/30/08)				
Acceptable Condition	-	-	-	-
1	0	100%	0	0%
2	7	29%	1	100%
3	130	4%	6	100%
Total	137		7	
2009 Progress to Date (8/10/09)				
Acceptable Condition	-	-	-	-
1	1	100%	0	100%
2	6	33%	0	100%
3	125	0%	0	100%
Total	132		0	

Conductors

There are approximately 3,400 miles of sub-transmission circuits. The Company previously had estimated 4,000 miles of circuits, but has updated this estimate based on the helicopter survey described above and the GIS/GPS foot patrol of all active lines performed.

The age profile of sub-transmission conductors is provided in Figure III-20.

Figure III-20.
Age Profile of Sub-transmission Conductor



As discussed in last year's report, there is no specific strategy to replace sub-transmission conductors, however, conductors that are smaller than 1/0 Cu are evaluated by the engineering department during refurbishment projects and will be replaced at the same time as pole replacements, if necessary due to condition. Reconductoring will also be performed as part of pole replacement projects if conductors are identified in a planning study as being near their thermal limit.

Post Insulators

As noted in last year's report, the Company conducted an internal review of insulator failures on sub-transmission lines due to several post insulator failures. The outcome of this review was a project, which has been completed, to replace post insulators on angled structures on the sub-transmission circuits between [redacted], which is the region that experienced the most insulator failure problems. A 4 mile replacement project was also performed on the [redacted] line where cracked insulators were found on most structures; this is a radial line and no subsequent insulator problems have been reported.

Foundations

It is not yet known what the age related life limiting process will be for tower foundations (footings). However, it would be expected that the foundations would also be scrapped once the tower has reached the end of its life. Hence foundation lives are directly linked to and limited by the tower structure lives.

The table below provides an overview of repairs which have recently been performed on steel towers.

Table III-57
Foundation Repairs

Circuit	kV	Tower #(s)	Foundation Work Carried Out
[redacted]	46	#28	4 leg grill foundation repair
		#27, 29, 30, 35, 36, 39, 40	2 leg grill foundation repair
		#31 and 34	4 leg concrete foundation repair
		#33	2 leg concrete foundation repair
	46	#7, 17, 21, 45, 53, 86, 118, 123	Repairs to Flex and Square based towers
		#10 and 19	Inspection below grade
	34.5	#39	Foundation repaired (reimbursable by Brookfield Hydro)
	34.5	#6 and 11	Repaired foundations
	46	#10 and 19	Repaired foundations on Square base
	46	#9	Repair planned

Remedial Actions Performed and Planned

Table III-58 contains a list of the sub-transmission lines that have or will have work carried out on them during 2009-2010 in upstate New York (*i.e.* they been designed, completed, scheduled or are due to be started in calendar years 2009-2010).

Table III-58.
Sub-Transmission Line Projects for 2009 and 2010

Division	[redacted]	kV	Scope
Central		46	6 miles double circuit replacement, single structure refurbishment and reconductoring over two years
Central		34.5	Refurbishment and reconductoring
West		34.5	Reconductor and refurbishment
Central		34.5	Line refurbishment
Central		34.5	Line refurbishment
Central		23	1 mile line relocation and switch structure relocation
Central		23	Line refurbishment
Central		46	Line refurbishment
Central		46	Line refurbishment

Table III-58 (continued).
[redacted]ojects for 2009 and 2010

Division	[redacted]	kV	Scope
East	[redacted]	34.5	Replace existing overhead and UG cable with bigger cables
East	[redacted]	69	Replace switch structures
East	[redacted]	34.5	Line refurbishment
East	[redacted]	34.5	Line refurbishment
East	[redacted]	34.5	Line refurbishment and partial relocation
East	[redacted]	69	Line refurbishment
East	[redacted]	69	Line refurbishment
Central	[redacted]	34.5	Eliminate station and reconnect lines
West	[redacted]	23	Replace approx 0.5 miles aerial cable with Hendrix cable
Central	[redacted]	34.5	Pole replacements
West	[redacted]	34.5	Pole replacements and line relocation
West	[redacted]	34.5	Relocate line for IDA. Replace Aerial Cable.
Central	[redacted]	46	7 miles relocation for NYSDOT road work
Central	[redacted]	23	Tap to high falls pole repl.
Central	[redacted]	34.5	Reconductor
West	[redacted]	34.5	Bergen tap rebuild and reconductor and Main line rebuild
West	[redacted]	34.5	Line relocation
West	[redacted]	34.5	Line refurbishment
West	[redacted]	34.5	Line refurbishment
West	[redacted]	34.5	Line refurbishment
East	[redacted]	34.5	Line refurbishment
East	[redacted]	34.5	Line refurbishment
West	[redacted]	34.5	Line refurbishment
Central	[redacted]	46	Replace 10 structures
East	[redacted]	69	Relocate structures due to creek problems
Central	[redacted]	46	Reconductor 6 miles and rebuild
Central	[redacted]	46	Refurbish 10 towers and replace relocate 3 structures
Central	[redacted]	23	Relocate line for 1 mile
Central	[redacted]	23	Line refurbishment
West	[redacted]	34.5	Line refurbishment
West	[redacted]	34.5	Line refurbishment
East	[redacted]	34.5	Rearrange circuit for reliability
West	[redacted]	34.5	add lightning arrestors every 2-3 structures
West	[redacted]	34.5	1.5 miles of new/refurbished line
West	[redacted]	34.5	5 mile new 34.5kV line for Non Utility Generator
East	[redacted]	34.5	NYSDOT relocation
Central	[redacted]	46.	Alder Creek Bypass
West	[redacted]	23	Rebuild .25 mile section and rearrange lines
East	[redacted]	23	Rebuild structure tops for insulator replacement
West	[redacted]	34.5	2 structures (4 poles) and sheet piling due to creek problem

Line refurbishments can include replacement of all or part of all line components including structures, insulators, cross arms, guys and anchors, switches, and small sections of conductor and overhead ground wire.

With regard to foundations, National Grid is currently developing a program commencing in FY2011. The formation of the work program is subject to change but currently consists of the following potential projects listed in Table III-59.

Table III-59
Foundation Remediation Work Program

Line No.	kV	Line Section		Scope
		From	To	
21/27	46	[redacted]		Central/Refurbish footing and paint towers
6	69			East/Refurbish footing and paint towers
91/92	34.5			West/Refurbish towers to be used for line 704-34.5kv after relocation for Transmission
25	46			Central/Refurbish footing and paint towers
4	69			East/Refurbish footing, relocate in part (1 mile) and paint towers.
704	34.5			West/Refurbish footing and paint towers
29/23	46			Central/Refurbish footing and paint towers
3	69			East/Refurbish footing and paint towers. Relocate and replace some structures?
601-604	23			West/Refurbish footing and paint towers. Some structure and OHGW work.
21,22,26	23			Central/Refurbish footing and paint towers. Some structure and OHGW work
7,8	69			East/Refurbish footing and paint towers. Some structure and OHGW work
Various	34.5			West/Refurbish footing and paint towers as found on mostly wood lines
Various	34.5			Central/Reburbish footing and paint towers as found.
17,18	34.5			East/Refurbish footing and paint towers
Various	12			West/Refurbish footing and paint 12kv SubTransmission towers still left

After an initial investigation of automation and communication technologies, National Grid began a targeted Sub-Transmission automation pilot in 2008, with systems becoming operational in 2009. The following lines have operational automation systems that went live in January 2009:

- [redacted] 22 Line (23 kV)

- [redacted]22 Line (34.5 kV)

The following lines have equipment installed and are in the final stages of testing and coordination with substation EMS systems and operational controls, and are expected to be on-line before the end of 2009:

- [redacted]

These systems use a distributed intelligence through local controls and switches, with peer to peer communication through to a local substation Energy Management System (EMS) uplink point achieved using spread spectrum 900 MHz radios. By uplinking to EMS National Grid is able to bring the SCADA[45] capability of the automation devices to the Company's Control Centers. In addition all data is brought back to a central database warehouse.

An estimated reliability improvement for all of the sub-transmission circuits in the pilot, in terms of annual benefits of fully operational systems are:

- Reductions in customers interrupted (CI[46]) of 16,000
- Reduction of customer minutes interrupted (CMI[47]) of 3,460,000

The automation on the [redacted] #22 34.5 kV circuit operated twice in April, 2009, yielding 52 percent of the annual CI benefit and 37 percent of the annual CMI benefit estimates.

National Grid continues to monitor the performance of the operational systems, and is in the process of developing a complete prioritized list of feeders and subtransmission circuits where automation value is estimated as greatest. This will create a basis for a work plan going forward, and be an enabler for any smart grid applications.

Rights Of Way

National Grid has extensive rights of way (RoW's) relating to the sub-transmission overhead lines.

The Sub-Transmission line Customer Minutes Interrupted (CMI) values were analyzed in 2007 to identify and prioritize candidates for RoW widening and maintenance based on reliability. The analysis resulted in 70 lines being identified, as candidates for action. Of these 70 lines:

[45] Supervisory Control and Data Acquisition
[46] CI is proportional to SAIFI, the System Average Interruption Frequency Index
[47] CMI is proportional to SAIDI, the System Average Interruption Duration Index

- 32 lines have been addressed completely (end-to-end)
- three lines have been addressed out to present rights limit and associated restrictions to an acceptable level
- 13 lines are on the present FY widening list
- 22 lines remain in the plan for FY11 and FY12

Lines remain on the list that have not yet been widened or have certain attributes that make it difficult to obtain the optimal width within a comparable per mile cost as other lines. This list will continue to be worked, with the following adjustments made to the program.

- Some lines have easement restrictions that make it difficult to achieve the optimal ROW width. Easements may need to be bought, adjusted or improved to achieve these widths on lines that have a high importance rating.
- The most current reliability data will be evaluated to update the list of widening candidates, in conjunction with the encroachment reports from the helicopter survey. This evaluation has been initiated.
- The goal of the ROW program is to widen 100-150 miles on an annual basis, adjusted according to the lines selected.
- Previously widened lines need to be reviewed for hazard trees, placed on cycles

In some cases, the EHTM program has mitigated possible causes of unreliability without needing to address RoW issues. A review of all remaining lines and updated reliability performance will take place in 2010. This will include an investigation of proactive metrics to identify work candidates to supplement CMI indicators

Underground Cables

There are approximately 1,100 miles of sub-transmission underground cable that are a mix of newer good condition cables, and includes many older and many poor condition cables. Approximately one-half is more than 47 years old and one-third is more than 60 years old.

Condition and Performance Issues

Cable failures are tracked, but do not usually have an impact on reliability as the sub-transmission underground system is heavily networked and an individual cable failure will not necessarily lead to an interruption of supply. Locations where there are repeated or frequent failures are targeted for cable replacement.

Cable replacement candidates are identified not only on known failure concentrations, but also on loading and anticipated load growth considerations. In addition, where there is no spare duct or the present duct banks have collapsed, the cables are marked for installation of new duct banks parallel to the existing duct banks.

Data related to underground cables and related equipment is in need of analysis and review; a scoping study for a survey of underground equipment is underway. It is expected that survey project proposals, including data conversion projects from existing data sources, will be generated out of the study by late Spring 2010.

A review of cable failure work in Buffalo, recorded under a single project, yielded over 220 separate repair activities over the period 2005-2008.

Table III-60
Buffalo Cable Repairs (2005-2008)

Year	2005	2006	2007	2008
Number of repairs	80	38	43	63

These repairs were one or two cable sections; there was no clear pattern to the failures in terms of cable location or type.

Remedial Actions Performed and Planned

National Grid is continuing to finalize the Cable Replacement Strategy and project scopes to replace poorer condition cables greater than 60 years of age over a 15 year period in the fiscal year starting April 1, 2010. The Company has currently completed project scopes for FY11 and FY12, which include 2 project scopes in NY Central, 1 in NY East and 21 in NY West, displayed in Table III-61. Project scopes are created for circuits based on recommendations from local engineers and capacity/loading issues. These SubTransmission underground circuits will have project scopes created. In the interim, cables that have been identified as poor performers by the engineering department continue to be replaced or are included in project scopes for future budget years.

Table III-61.
Project Scopes Created for NY Divisions Based on Engineering Recommendations and Asset Condition

Division	Project Scopes Created	Feeders
Central	2	[redacted]
East	1	[redacted]
West	21	[redacted]

In addition, an initiative is being developed to review available test and inspection techniques in order to improve underground cable condition information. The plan is to investigate on-line testing techniques in an effort to characterize standard signatures and anomalies related to underground cables.

The following underground cable replacement/addition projects are either ongoing or in development:

- An ongoing annual program has been developed to install new underground conduit and cable in order to upgrade the aging 23 kV infrastructure in the City of Buffalo based on cable failures and repairs. The first targets of the program are duct banks with insufficient spare conduit. Spare conduit is necessary to provide an alternate path for pulling new cable should the existing cable become impossible to remove.

- In order to address load growth in the City of Buffalo, a new 23kV cable will be extended from [redacted] Station to serve Stations 22, 23 and 24. Once the new cable is installed, the other cables at this location will be replaced, one at a time, with new cable. This project is still in the design phase. Once these replacements are complete each remaining cable network will be reviewed to identify pinch points. This analysis will be done for the [redacted] [redacted] and [redacted] 23kV circuits. After all pinch points are identified, a plan to add new duct bank will be drafted and work will be scheduled.

- In Eastern division, the [redacted] 2/13 replacement cable project is targeted to be completed in 2009. In addition, two [redacted] cables that run in the same duct bank under [redacted] have had numerous failures and are therefore targeted for replacement with the design process under way: (1) [redacted] and (2) [redacted] - from [redacted].

- Four circuits relating to South Mall are experiencing leaking splices: (1) [redacted] These cables are approximately 45 years old and will be replaced. This project is in the design process at present:

In addition, the following circuits are scheduled for detailed analysis and review in 2009-2010 time frame:

- The [redacted] cable has a history of failures and is a candidate for replacement, and is prioritized as it is a crossing under the Hudson River. There are two other feeds to Rensselaer, both carried by the same overhead structures, which means that there is significant risk should an overhead structure fail and supply becomes dependent on the cable. An evaluation of the area from a planning perspective will be performed, particularly in relation to the large generating plant expected to come on line in 2011, Empire Generating, which may impact loading on these circuit and result in thermal concerns as load increases.[48]

- [redacted] cable has suffered several collapsed splices and leaking potheads at the [redacted] end. There have been several failures on the [redacted] end of the circuit, leading to industrial customer interruptions.

- [redacted] #5 (34kV) is a low pressure gas filled (LPGF) Paper Impregnated Lead Sheathed (PILC) cable. Pressurizing LPGF cables were discontinued for

[48] There were frequent thermal issues on the Bethlehem 10 & 14 lines when the Albany Steam Plant was upgraded until National Grid replaced all the Low Pressure Gas Filled (LPGF) cable on the two circuits

environmental and reliability concerns. The LPGF is used for electrical insulation and most of the LPGF still in our system (including [redacted]) are no longer filled with the low pressure gas and thus are targeted for removal. A project scope has been created for this circuit.

Summary

The National Grid Sub-Transmission system is ageing and deteriorating; on going repairs and refurbishments for both overhead line and underground assets are reactive in nature. A program to proactively manage condition in the future is necessary to ensure that the Sub-Transmission system is able to provide the level of service expected and required. There are a number of capital programs identified to support both repairs and refurbishment.

On going Inspection and Maintenance Program activities generate work required to improve system condition.

The helicopter survey is providing valuable data for determination of actual circuit lengths and conditions and will be used to support line refurbishment and replacement.

On going underground failures are being addressed, but an initiative is underway to develop a more condition centric approach, using new on-line and off-line test methods.

Distribution/Sub-Transmission automation pilots have yielded benefits in line with estimates and supports implementation of automation on a wider basis, coupled with substation EMS installations for data management and communication.

- Capital programs are in place to address system condition on a proactive basis including:
- Sub-transmission Reliability Enhancement Program Line
- Sub-transmission Reliability Enhancement Program Automation
- Sub-transmission Reliability Enhancement Program Line Rebuild
- Sub-transmission Reliability Enhancement Program Underground Cable

C. Distribution System

This section of the report provides a detailed description of the distribution system asset condition for overhead lines and underground cables. It brings together all the available distribution infrastructure information from a variety of different sources including the inspection and maintenance program[49] and provides a balanced view of the condition and performance issues affecting the network.

The distribution system is generally in sound condition. National Grid continues to gather data and monitor assets in a proactive manner to ensure that any increasing trends are identified and the system is fit for purpose.

Table III-62 summarizes the distribution overhead line and underground cable assets.

Table III-62
Summarized Distribution Line Asset Quantities

Main Asset	Inventory
Poles	1,232,500
Transformers: Pad/Pole/Underground	446,600
Primary Conductor (Circuit Miles)	35,900 miles
Cutouts	260,500
Switchgear	3,100
Capacitor Banks	4,700
Reclosers/Sectionalizers	1,040
Line Regulators	3,400
Primary Underground Cable (Circuit Miles)	6,900 miles
Manholes	16,800
Vaults	1,800

This following subsections will discuss asset categories such as overhead lines (structures, transformers and other ancillary equipment), underground equipment (cables, vaults and manholes, and other equipment), and large programs (Reliability Enhancement Program, Engineering Reliability Reviews, and others). Where necessary further information is provided in the exhibits referenced throughout this document.

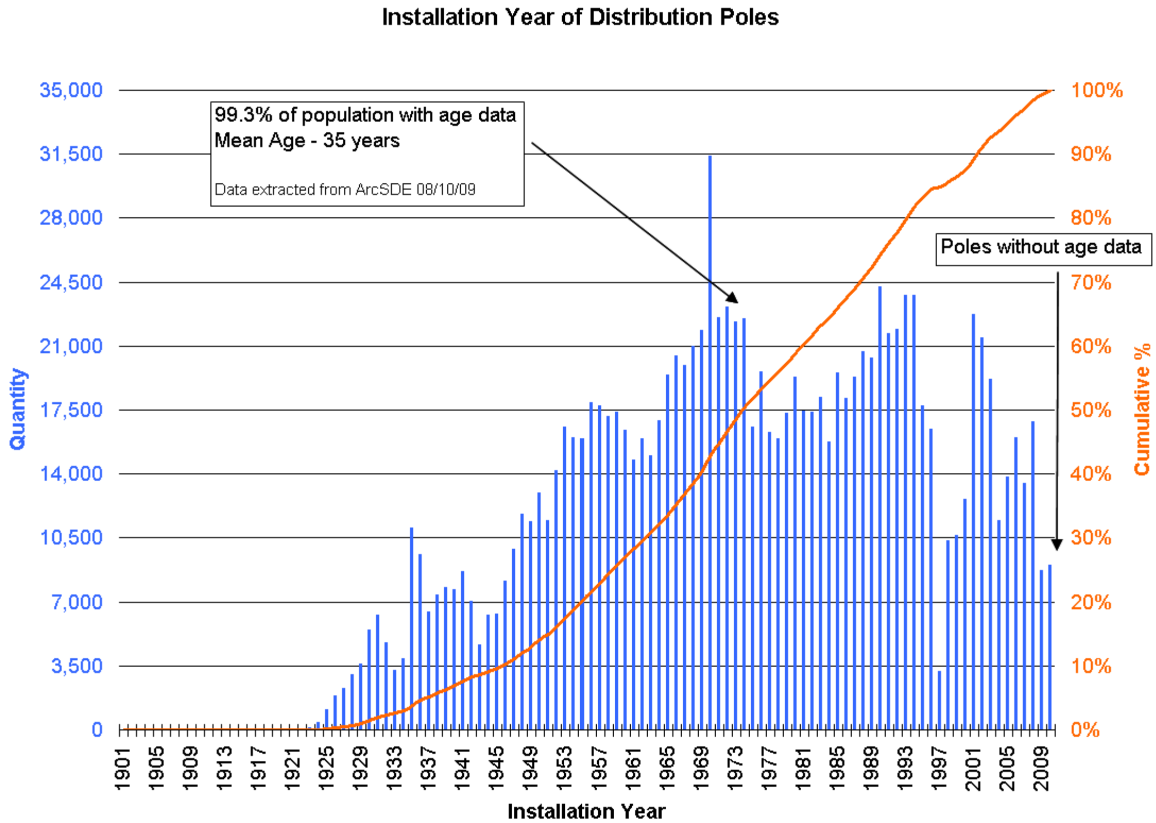
[49] The Inspection and Maintenance (I&M) strategy is the primary means of assessing, collecting and addressing issues on the overhead and underground electric system. The I&M program allows the Company to assess the condition of distribution and sub-transmission assets to structure a proactive replacement plan for each asset. Ultimately, the I&M will create a higher level of discipline in maintaining system components that do not need immediate replacement. Most importantly, the beneficial impact on the safety and reliability of the system will be discernible by customers because the operating integrity will be raised and maintained at a relatively high level.

Overhead Lines

Structures

Distribution structures include towers, poles, crossarms, guys, and anchors. Distribution structures are in generally good condition with more than 96 percent of structures inspected in acceptable condition. There are approximately 1.23 million distribution poles on National Grid's New York system with an average age of 35 years (Figure III-21). Approximately 24 percent of the total population of wood poles is more than 50 years old and approximately twelve percent are more than 60 years old. The following information addresses all poles regardless of material.[50] Distribution assets are also attached to approximately 24,400 transmission and/or sub-transmission structures. The condition of those structures is discussed in either the transmission or sub-transmission section of this report rather than this section, as the distribution component is ancillary to the structure.

Figure III-21
Age Profile of Distribution Poles



50 Fewer than 500 (0.04 percent) of distribution poles are made of a material other than wood (i.e. concrete, fiberglass, or steel).

Condition and Performance Issues

Between December 1, 2008 and August 10, 2009, inspections were completed on 188,800 distribution poles, which represent approximately 15 percent of the population. Based on these inspections, 1.9 percent of the inspected poles, approximately 3,600 poles, are candidates[51] for replacement over the next three years. The 1.9 percent replacement candidate rate for 2009 inspections is nominally equal to the 2008 inspections at 2.4 percent. Table III-63 and Figure III-22 shows the results of all pole related priority codes. The majority of the listed codes will not result in pole replacement. The 2008 summary data includes codes from September 4, 2008 to November 30, 2008 that were not included in the 2008 report due to the fact that that report was filed prior to the end of 2008. Also, the table includes survey results that did not result in pole replacement.

Table III-63
Distribution Wood Poles Inspection Results

Level	Replace Codes			Repair Codes		
	Number of Poles*	Percent Codes vs. Inspections**	Percent Completed	Number of Poles*	Percent Codes vs. Inspections**	Percent Completed
2008 Summary (including data between 9/4/08 and 11/30/08)						
Acceptable Condition	266,768	96.71%		271,170	98.31%	
1	23	0.01%	100%	2	0.00%	100%
2	1,631	0.59%	86%	145	0.05%	96%
3	7,411	2.69%	22%	4,516	1.64%	27%
Total	275,833	100.00%		275,833	100.00%	
2009 Progress to Date (8/10/09)						
Acceptable Condition	184,572	97.74%		186,634	96.59%	
1	11	0.01%	100%	0	0.00%	100%
2	918	0.49%	3%	90	0.53%	12%
3	3,332	1.76%	3%	2,109	2.88%	3%
Total	188,833	100.00%		188,833	100.00%	

*These numbers reflect priority codes against poles; individual poles may have more than one code against it.
**Percent codes versus inspections compares the number of assets with recorded priority codes to the number of assets inspected.

While only 15 percent of the distribution wood poles have been inspected in 2009, the Company has no reason to believe that future pole inspection results will not produce similar results with respect to pole condition. However if there are significant differences, these will become known within the five year inspection cycle.

[51] Poles identified through the inspection program are referred to as candidates because a small percentage may be double counted due to missing GISID data in the Computatpole database and early replacements of Level 3 poles due to other construction projects.

Figure III-22
Install Year Profile Inspected versus to be Replaced

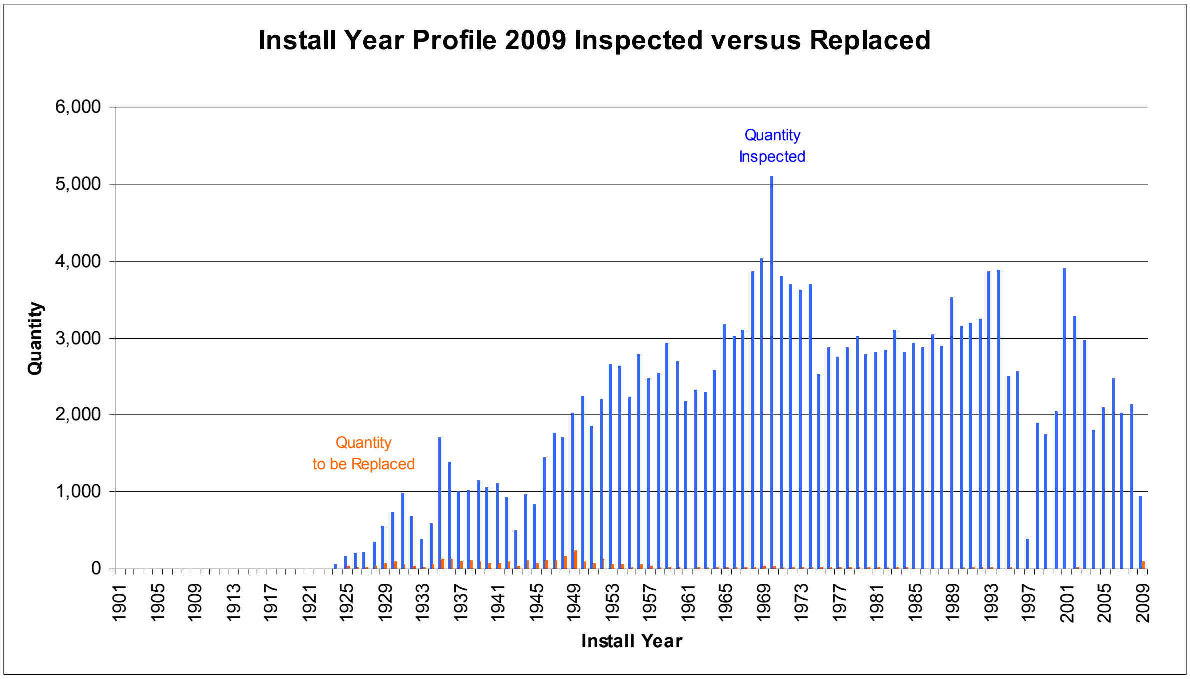
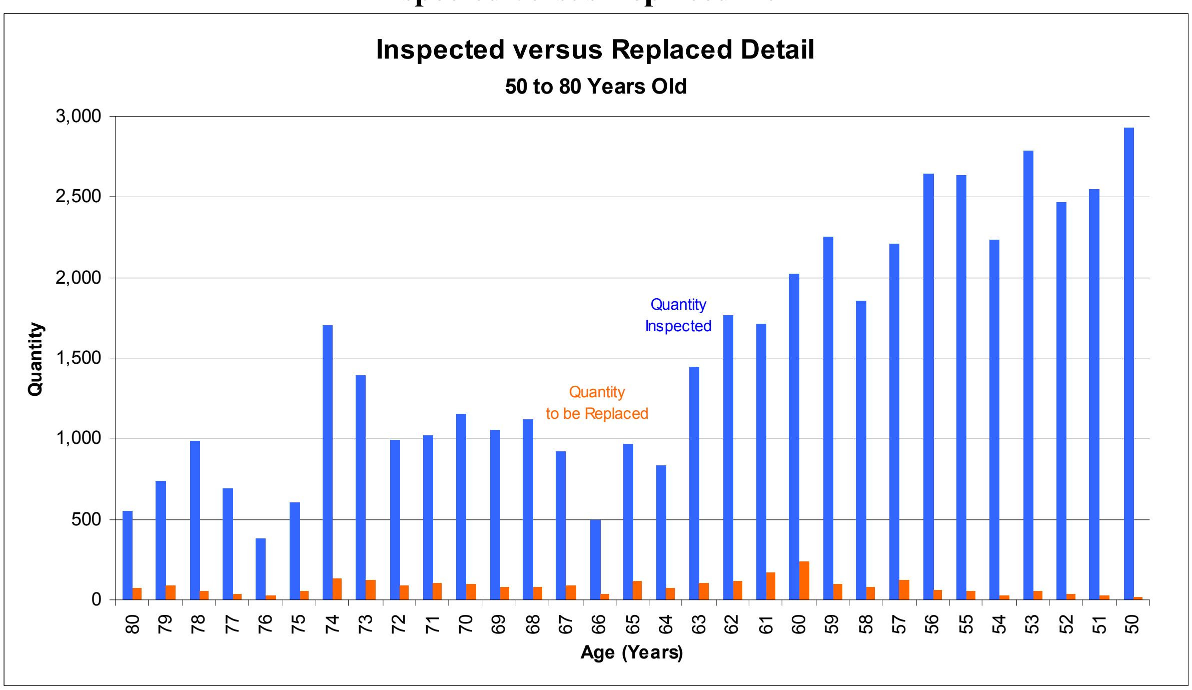


Figure III-23
Inspected versus Replaced Detail



Figures II-22 and II-23 above compare the installation year profiles of poles inspected compared to poles that are candidates for replacement based on inspection. This profile is very consistent with the 2008 profile showing increased replacements between 50 years to 80 years.

In addition to distribution system pole replacement candidates, inspections look for issues with crossarms, guys and anchors. The type of condition issues include damaged crossarms, loose pins and braces, excessive slack, broken guy wires, or a need for anchors.

Crossarms, braces and pins are commodity type assets which are not tracked individually if their condition is found acceptable, however estimates can be made on the number of assets inspected. As the inspections represent approximately 15 percent of the pole plant, it can be reasonably assumed that this is approximately the same percentage of these commodity assets reviewed. The percentage of codes returned for crossarms and braces is nominally equal comparing the complete 2008 data (1.6 percent) to the partial 2009 data (1.5 percent). Tables III-64 and 65 provides the condition assessment for these assets.

Table III-64
Crossarms, Pins and Braces Inspection Results

Level	Crossarms		Braces and Pins	
	Number of Assets	Percent Codes Completed	Number of Assets	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)				
Acceptable Condition	-	-	-	-
1	23	100%	23	100%
2	349	94%	379	94%
3	1,600	31%	1,937	25%
Total	1,972		2,339	
2009 Progress to Date (8/10/09)				
Acceptable Condition	-	-		
1	4	100%	11	100%
2	124	10%	274	17%
3	691	4%	1,675	2%
Total	819		1,960	

Table III-65
Guys and Anchors Inspection Results

Level	Guys*			Anchors*		
	Number of Assets	Percent Codes vs. Inspections	Percent Codes Completed	Number of Assets	Percent Codes vs. Inspections	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)						
Acceptable Condition	24,207	85.24%		28,315	98.70%	
1	4	0.01%	100%	0	0.00%	100%
2	1,388	4.89%	81%	56	0.20%	91%
3	2,801	9.86%	24%	29	0.10%	41%
Total	28,400	100.00%		28,400	100.00%	
2009 Progress to Date (8/10/09)						
Acceptable Condition	17,304	81.24%		21,205	99.55%	
1	0	0%	100%	0	0%	100%
2	2,205	10.35%	12%	74	0.35%	11%
3	1,791	8.41%	3%	21	0.10%	29%
Total	21,300	100.00%		21,300	100.00%	

*Assuming one guy per anchor. These numbers reflect priority codes against guys and anchors, individual guys and anchors may have more than one code against them.

Overall, these quantities are at or below historical levels and do not present a growing concern. Neither crossarms nor pins/braces are objects within the Geographic Information System (GIS); therefore quantities cannot be calculated directly. Using a rough estimate based on construction type, it is estimated that approximately 220,000 crossarms and 810,000 pins/braces were inspected. Using this estimate, reported maintenance codes for both these items is less than one percent of the population, indicating an overall healthy asset condition.

Remedial Actions Performed or Planned

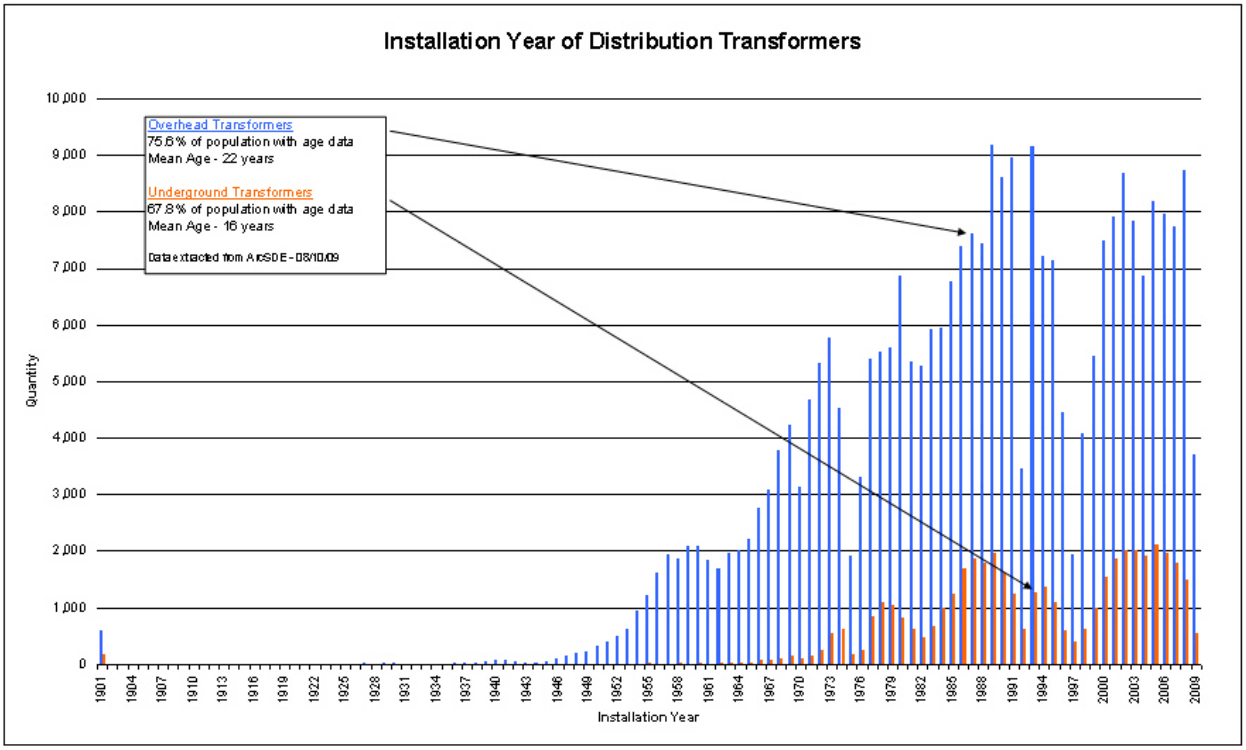
Approximately 3,080 poles were replaced to date as a result of the 2008 inspections in addition to the 2,560 replaced by the targeted pole replacement program in FY09. Thus far approximately 50 percent of the pole candidates identified in the 2008 inspections have been replaced, including 100 percent of Level 1 and 86 percent of Level 2 codes. Thus far in 2009, approximately 160 poles were replaced as a result of the 2009 inspections in addition to 370 poles (as of the end of August, 2009) replaced by the targeted pole replacement program for FY10. More than 720 poles are planned for replacement as part of the FY10 targeted pole replacement program.

Work associated with pole maintenance is captured by the I&M Program and the Reliability Enhancement Program (Feeder Hardening and Enhanced Infrastructure).

Overhead and Padmounted Transformers

There are approximately 446,600 overhead and padmount distribution transformers. This is 6,600 more than reported last year. The increase is due to rounding to a lower level compared to last year and increased confidence in the data due to multiple years of experience working with the information. The average age of overhead units is 22 years with three percent older than 50 years and less than one percent older than 60 years. The average age of the padmount units is 16 years with less than one percent older than 50 years. The average size of overhead units is 27 kVA, for padmount units the average size is 107 kVA. The installation year profile data is shown in Figure III-24.

Figure III-24
Age Profile of Distribution Transformers



Condition and Performance Issues

Between December 1, 2008 and August 10, 2009 inspections were completed on approximately 57,000 overhead and 9,900 padmounted transformers, which represent approximately 15 percent of the population. Based on these inspections, less than one percent of both the inspected overhead and padmounted transformers are candidates for replacement. Table III-66 and II-67 summarizes the results.

Table III-66
Overhead Transformer Inspection Results

Level	Replace Codes			Repair Codes		
	Cracked or Broken Bushings	Weeping Oil	Percent Codes Completed	Lightning Protection	Grounding/ Bonding	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)						
1	0	0	100%	0	0	100%
2	16	105	96%	0	3,952	89%
3	70	0	31%	6,133	0	27%
2009 Progress to Date (08/10/09) (57,000 inspected year to date)						
1	1	2	100%	0	0	100%
2	8	80	10%	0	3,803	13%
3	36	0	11%	1,678	0	5%

Table III-67
Padmount Transformer Inspection Results

Level	Replace Codes			Repair Codes			
	Cracked or Broken Bushings	Weeping Oil	Percent Codes Completed	Physical Damage	Termination Tracking	Grounding/ Bonding	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/31/08)							
1	0	8	100%	36	0	1	100%
2	0	63	97%	260	0	12	98%
3	3	0	33%	104	1	0	26%
2009 Progress to Date (08/10/09) (9,900 inspected year to date)							
1	0	4	100%	10	0	0	100%
2	0	40	25%	204	0	6	19%
3	0	0	100%	70	1	0	3%
3	0	0	100%	70	1	0	3%

Remedial Actions Performed and Planned

Approximately 210 transformers were replaced to date as a result of the 2008 inspections in addition to the 518 replaced by the heavily-loaded transformer program in FY09. Thus far approximately 80 percent of the transformers identified in the 2008 inspections have been replaced, including 100 percent of Level 1 and 96 percent of Level 2 codes. Thus far in 2009, approximately 22 transformers were replaced as a result of the 2009 inspections in addition to 290 transformers (as of the end of August, 2009) replaced by the heavily-loaded transformer program for FY10. More than 300 transformers are planned for replacement as part of the FY10 heavily-loaded transformer replacement program.

Work associated with transformer maintenance is captured by the Inspection and Maintenance Program and the Reliability Enhancement Program (Feeder Hardening and Enhanced Infrastructure).

Conductors

There are approximately 35,900 circuit miles of primary distribution conductor, of which 14 percent is #4 AWG[52] or smaller (excluding #4 AWG Aluminum Conductor Steel Reinforced). Primary conductor is in generally good condition with less than one priority code recorded per six circuit miles of primary inspected. No age profile data is available for conductors because age data was not recorded on system maps until after the implementation of a GIS in 2000.

Condition and Performance Issues

At this time, most conductor replacement projects are being prioritized to address loading and/or voltage issues. Inspection results for 2009 for approximately 4,800 miles (~13 percent) of conductor found the issues shown in Table III-68 and III-69. The percentage of codes returned for conductors is nominally equal comparing the complete 2008 data to the partial 2009 data. The 2008 summary data includes codes from September 4, 2008 to November 30, 2008 that were not included in the 2008 report due to report time frame.

Table III-68
Distribution Primary Conductor Inspection Results

Level	Broken Strands or Damaged Connectors	Percent Codes Completed	Insufficient Clearance or Improper Sag	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)				
1	5	100%	113	100%
2	56	98%	178	96%
3	20	25%	81	41%
2009 Progress to Date (8/10/09) (4800 miles inspected year to date)				
1	1	100%	60	100%
2	68	21%	134	30%
3	15	0%	72	4%

52 American Wire Gauge

Table III-69
Distribution Spacer Cable Inspection Results

Level	Bracket Damage	Messenger/ Bonding Issues	Damaged/ Missing Spacers	Uncovered Splice	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/31/08)					
1	1	0	1	0	100%
2	4	0	31	0	97%
3	13	759	64	28	12%
2009 Progress to Date (8/10/09) (4800 miles inspected year to date)					
1	0	0	0	0	100%
2	1	0	24	0	20%
3	13	320	72	12	1%

These quantities are at or below historical levels, as per previous condition assessments, and do not present a growing concern, but will be addressed over the next three years as part of the I&M Program.

In 2008 approximately 190 circuit miles of new conductor was installed. Thus far in 2009, more than 80 miles (through July, 2009) has been installed. An unknown percentage of this new primary is replacement conductor.

Remedial Actions Performed and Planned

At this time, the Company has initiated more than 20 distribution conductor replacement projects have been identified by the engineering department due to loading or voltage issues. These projects are typically associated with the Enhanced Infrastructure portion of the Reliability Enhancement Program. Future plans call for the implementation of the primary wire replacement strategy which may use inspection data to help prioritize competing primary replacement projects.

Cutouts

There are approximately 260,500 cutouts on the distribution system. This number is 33,500 higher than last year's report due to the installation of additional sectionalizing fuses and cutouts for distribution transformers.

Condition and Performance Issues

These assets are in generally good condition based on the number of priority codes recorded during inspections (< 0.5 percent). Potted porcelain cutouts (PPC) have been identified for replacement due to the mechanical failure mode and potential hazard associated with them as described in the Potted Porcelain Cutout Strategy. The inspection program has identified approximately 19,500 potted porcelain cutouts in the last two inspections cycles and replaced 20 percent of them.

Between December 1, 2008 and August 10, 2009 inspections were completed on over 34,000 cutouts, which is approximately 15 percent of the population. Based on these inspections, less than one half percent of the inspected cutouts require replacement due to condition within one year of the assessment. An additional 21 percent are potted porcelain cutouts which require replacement over the next three years. Table III-70 shows the results.

Table III-70
Cutout Inspection Results

Level	Number of Assets	Percent Codes vs. Inspections	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)			
Acceptable Condition	34,779	73.77%	
1	20	0.04%	100%
2	137	0.29%	90%
3	12,210	25.90%	28%
Total	47,146	100.00%	
2009 Progress to Date (08/10/09)			
Acceptable Condition	26,626	78.31%	
1	16	0.05%	100%
2	108	0.32%	28%
3	7,250	21.32%	4%
Total	34,000	100.00%	

Remedial Actions Performed and Planned

A strategy exists to replace all potted porcelain cutouts on the system. The cutout program will replace all of the potted porcelain cutouts through multiple programs (I&M program, feeder hardening, planned replacements and everyday work). To date, the Company has replaced nearly 50,700 potted porcelain cutouts of the approximately 120,000 units originally installed on the system.

Work associated with cutout maintenance is captured under the I&M Program and the Reliability Enhancement Program (Potted Porcelain Cutout Replacements).

Switchgear

There are approximately 3,100 switchgear on the system. Switchgear are generally in good condition, with only a minimal number of issues discovered in the inspection program.

Condition and Performance Issues

Between December 1, 2008 and August 10, 2009, inspections were completed on 465 switchgear, which represent approximately 15 percent of the population. Table III-71 shows the results of all switchgear related priority codes, the majority of the listed codes will not result in switchgear replacement. The 2008 summary data includes codes from September 4, 2008 to November 30, 2008 that were not included in the 2008 report due to report time frame.

Table III-71
Switchgear Inspection Results

Level	Base broken/ damaged	Door Broken/ Damaged	Barrier broken/ damaged/ unset	Missing Ground	Total	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)						
1	0	0	0	0	0	0%
2	7	2	2	3	14	100%
3	4	0	1	0	5	60%
2009 Progress to Date (8/10/09) (465 inspected year to date)						
1	1	0	0	0	1	100%
2	3	1	0	0	4	0%
3	4	0	1	0	5	40%

Remedial Actions Performed and Planned

The Company addresses switchgear through the Inspection and Maintenance Program and any issues identified, as per the above table, are scheduled in the work plan.

Capacitors

There are approximately 4,700 capacitor banks on the distribution system providing about 135 MVAr[53] of reactive support. Capacitor banks are in generally good condition based on the number of priority codes recorded during inspections. These 4,700 banks are made up of both switched and fixed units in both single phase and three phase configurations. The breakdown is detailed in Table III-72 below:

Table III-72
Capacitor Bank Count and MVAr

	Fixed		Switched
	Single Phase	Three Phase	Three Phase
Quantity	1,422	3,267	52
MVAr	15.8	109.6	9.7

Condition and Performance Issues

Between December 1, 2008 and August 10, 2009 inspections were completed on approximately 700 capacitor banks, which is approximately 15 percent of the population. Table III-73 shows the results.

[53] MVAr – Mega Volts Amps reactive

Table III-73
Capacitor Bank Inspection Results

Level	Replace Codes				Repair Codes			
	Blown Fuse/ Out of Service	Cracked/ Broken Bushings	Weeping Oil/ Bulging Tank	Percent Codes Completed	Lightning Protection	Grounding/ Bonding	Animal Guard Required	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)								
1	0	0	0	100%	0	0	0	100%
2	59	0	4	87%	0	9	0	100%
3	0	2	0	0%	86	83	702	27%
2009 Progress to Date (08/10/09) (700 banks inspected year to date)								
1	0	0	0	100%	0	0	0	100%
2	28	0	1	21%	0	4	0	50%
3	0	0	0	100%	38	21	437	4%

In addition to the five-year inspection cycle, capacitors banks are to be inspected annually as part of the Inspection and Maintenance Strategy. The need to install animal guards is by far the most common code recorded against capacitor banks during inspection. The lack of animal guards does not significantly impact system reliability.

Remedial Actions Performed and Planned

Work associated with capacitor maintenance is captured by the Inspection and Maintenance Program. Additionally small capital projects are in the budget to address feeder level capacity and voltage support issues on the distribution system. These small projects are discussed in the System Condition section of the report.

Regulators/Reclosers/Sectionalizers

A regulator is a device designed to automatically maintain a constant voltage level. Line regulators are used when primary voltage levels cannot be controlled within acceptable limits by capacitors and station regulation.

A line recloser is a circuit breaker with self-contained relaying that is capable of interrupting a fault and reclosing afterward to restore service. Both three-phase and single-phase versions may be installed. .

A sectionalizer is a self-contained, circuit-opening device used in conjunction with source-side protective devices to automatically isolate faulted sections of electrical distribution systems. A sectionalizer is very similar to a line recloser, the main difference being that sectionalizers cannot interrupt a fault. They can only open between reclose operations of an upstream circuit breaker or line recloser to isolate the fault

There are 990 reclosers, 3,400 voltage regulator units, and 48 sectionalizers on the distribution system. Reclosers and regulators are generally in good condition, with only a minimal number of issues discovered in the inspection program, as per Table III-74. Sectionalizers will be removed from service when they can no longer be maintained or they no longer meet the needs of distribution system, as per the relevant recloser/sectionalizer strategy. With the implementation of the Inspection and Maintenance strategy, Line reclosers and sectionalizers will be inspected semiannually and line regulators will be inspected annually in addition to the existing five-year cycle visual inspection. The maintenance will be performed consistently with the Inspection and Maintenance Program.

As part of the existing five-year cycle inspection program, Table III-74 shows the results of all regulators/reclosers/ and sectionalizers related priority codes between December 1, 2008 and August 10, 2009, the majority of the listed codes will not result in replacement. The 2008 summary data includes codes from September 4, 2008 to November 30, 2008 that were not included in the 2008 report due to report time frame.

Table III-74
Regulators/Reclosers/Sectionalizers Inspection Results

Level	Bushing Broken or crack	Improper/ missing bonding	lightning arrester	Animal Guard missing	Oil Weeping	Total	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)							
1	0	0	0	0	0	0	100%
2	0	0	0	0	2	2	100%
3	1	5	13	236	0	255	29%
2009 Progress to Date (8/10/09)							
1	1	0	0	0	0	1	100%
2	0	0	0	0	1	1	100%
3	1	12	6	171	0	190	1%

Remedial Actions Performed and Planned

In addition to the five-year inspection cycle, regulators are to be inspected annually; reclosers and sectionalizers are to be inspected semiannually as part of the Inspection and Maintenance Strategy.

Exhibit 6 provides details of the overhead distribution inspection results from December 1, 2008 through August 10, 2009.

Underground Assets

National Grid's underground distribution network includes primary and secondary network cables, protectors, transformers, and manholes and vaults. The Inspection and Maintenance Program inspected 6,980 handholes, 1,100 manholes and 70 vaults between December 1, 2008 and August 10, 2009. This represents ten percent of handholes, seven percent of manholes and four percent of vaults. Items inspected include the condition of the structures themselves, and the equipment contained within, such as cables, splices, transformers, and network protectors.

Exhibit 7 provides a detail summary of the underground inspection results from December 1, 2008 through August 10, 2009.

Primary Network Cables

There are approximately 6,900 circuit miles of distribution cable. This is 700 miles more than reported last year. The increase is due to increased confidence in the updated source data in GIS data, based on more consistent data analysis.

Condition and Performance Issues

The following Table III-75 lists the inspection results for Cable Vault Inspections Results which capture leaking cable/joints.

Table III-75
Primary Cable Vault Inspection Results

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

Remedial Actions Performed and Planned

National Grid is continuing to finalize the Underground Cable Replacement Strategy and developing project scopes to replace cables in poorer condition and greater than 60 years of age over a 15 year period in the fiscal year starting April 1, 2010. The long-term goal is the development of a common strategy for both distribution and sub-transmission underground primary cable supporting condition-based replacement to maintain/improve the reliability of this asset class. The Company has currently completed project scopes for FY11 and FY12, which include 10 for NY Central, 6 for NY East and 16 for NY West (Table III-76). The project scopes call for replacing 10 miles of UG Cable in each division (total of 30 miles between FY11 and FY12). Project scopes are created for circuits based on recommendations from local engineers and capacity/loading issues. In the interim, cables that have been identified as poor performers by the engineering department have been replaced or are included in project scopes for future budget years. Lead covered cables and Low Pressure Gas Filled cables are the two types of cables targeted for replacement.

Table III-76.
Project Scopes Created for NY Divisions Based on Engineering Recommendations and Asset Condition

Division	Project Scopes Created	Feeders
Central	10	[redacted]
East	6	
West	16	

Secondary Network Cables

The Company performs studies on a periodic basis to ensure secondary cables are within their loading limits per internal standards. Historically network systems are designed to be redundant and reliable. Networks are prioritized by load served and the number of customers on the network system.

Condition and Performance Issues

In general, the secondary network cable system is in sound condition. However, as reported in the 2008 Asset Condition report, the significant failure in downtown [redacted] occurring in April 2007 identified operational issues. There is an environmental requirement to shut down sump pumps in network vaults. Some of the residual damage is starting to show up such as rusting equipment, switching problems, transformer failures (seven in the [redacted]) this year. The temporary solution is to pump down vaults, which take in water. The ultimate solution is to retrofit approved sensors that will avoid the release of oil, resolving the environmental concern. This concern will be addressed in the UG Secondary Network Strategy currently being written.

The following Table III-77 lists the secondary networks including location, number of feeders and approximate peak load:

Table III-77
Secondary Network Listing

Location	Number of Feeders	Approximate Peak Load (MVA)
[redacted]	10	34
	4	4
	5	16
	8	14
	10	34
	7	22
	4	9
	5	6
	2	2
	16	109

Remedial Actions Planned and Performed

As a result of the [redacted] incident in April of 2007, the Company has initiated a number of studies to analyze the ability of the secondary network cables to clear during fault conditions to reduce the potential for a similar event to happen. A major upgrade on the [redacted] Secondary network is currently underway as a result of the study. Similar studies will also be initiated in the remaining network areas of the Company. A study on the Albany Network is currently in progress. Load flow studies have been completed on the [redacted] (10/2008), [redacted] (1/2009). All Networks in upstate NY will have a load flow study performed, but currently a schedule has not been created. A general network strategy is currently being developed to provide guidance and consistency to the network review process. The strategy development is expected to be completed by the end of the current fiscal year (March 2010).

The network systems are monitored and maintained. Network vaults are to have a visual and operation check once every 12 months. Network protectors are to have a full mechanical diagnostic once every 60 months (CMD protector every 24 months). The inspections are performed by the subway department, which is a subset of the underground department.

Network Protectors

There are approximately 800 network protectors currently in service; they are in good condition and receive scheduled maintenance. A general network strategy is currently being developed to provide guidance and consistency to the network review process, which will include and target Network Protectors. The strategy development is expected to be completed by the end of the current fiscal year (March 2010).

Condition and Performance Issues

Table III-78 summarizes inspection results for network protectors. Thus far, in 2009 there has been no priority codes reported against these assets.

Table III-78
Network Protector Inspection Results

Level	Worn Gaskets	Damaged Barriers	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)			
1	0	0	100%
2	2	1	100%
3	0	0	100%
2009 Progress to Date (08/10/09)			
1	0	0	100%
2	0	0	100%
3	0	0	100%

Remedial Actions Performed and Planned

A program is currently underway to replace network protector electro-mechanical relays with microprocessor based relays. A study is also underway to remove MG8 protectors with Type CCN relays in them from service. These are known to be obsolete and there is currently no replacement available for them.

Network Transformers

Transformers in network areas and those located in vaults are generally in sound condition. General network transformers serve many customers using an interconnected grid of secondary cables. This type of grid is supplied through many primary distribution 120V transformers (many more sources). Spot network transformers serve one customer with double contingency service. There will be multiple transformers in several vaults to supply one customer. The transformers can be distribution primary voltage to 480V or 120V. They are normally 480V on the low side. The NY Central division has installed one new spot network in 2009 with one more currently in construction. The number of Network Transformers are shown in Table III-79.

Table III-79.
Network Transformer (Xfmrs) Quantities

General Network	General Network Xfmrs	Spot network Xfmrs
Albany	114	45
Buffalo - downtown	150	109
Glens Falls	12	0
Schenectady	45	10
Syracuse - Ash St	87	43
Syracuse - Temple St	27	49
Troy	35	8
Utica	25	11
Watertown	18	5
Watertown - Clinton St	3	0

Inspection results for Network Transformers are shown in Table III-80.

Table III-80.
Network Transformer Inspection Results

Level	Missing Ground	Cracked/ Broken Bushings	Weeping Oil	Percent Codes Completed
2008 Summary (including data between 9/4/08 and 11/30/08)				
1	4	0	0	100%
2	6	3	14	96%
3	0	0	0	100%
2009 Progress to Date (08/10/09)				
1	0	0	0	100%
2	0	1	1	0%
3	0	0	0	100%

Oil Fused Cutouts

All known Oil Fused Cutouts (OFC's) have been removed from service in New York. Any remaining OFCs will be located via the Inspection & Maintenance program and removed from service by FY15/16 in accordance with the existing strategy.

Manholes and Vaults

There are approximately 16,800 manholes and 1,800 vaults across the system. Between December 1, 2008 and August 10, 2009, approximately 1,100 manholes and 72 vaults have been inspected.

Condition and Performance Issues

In general, manholes are in sound condition. As reported in the 2008 Asset Condition report, the typical means of degradation is weakening of the roof structure. When these instances are identified by Operations, a civil engineer will evaluate each location, determine which locations are in need of repair or replacement and rank them in priority order. The inspection results are summarized in Table III-81.

Table III-81
Manhole and Vault Inspection Results

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

Remedial Actions Performed and Planned

Approximately 13 vault roofs are scheduled for replacement in 2009 and seven are tentatively scheduled for 2010. All items identified in the inspection program shall be corrected in one year to three years depending on their Level.

Programs

The programs described here are system programs to provide reliability benefits and improve system performance.

Reliability Enhancement Program

The Reliability Enhancement Program is a separate program designed to significantly improve reliability through four programs:

- Feeder Hardening and Engineering Reliability Reviews – Both of these programs are described in this section
- Incremental Asset Replacement – Replacement of targeted assets (poles, transformers, underground cable, cutouts, etc.) is designed to improve the sustainability and reliability of the distribution system

- Incremental Vegetation Management – Enhanced Right of Way clearing and treatment and Enhanced Hazard Tree Maintenance (ETHM) removal of danger trees on critical sections of the distribution system
- Inspection and Maintenance – overhead and underground inspection program described in the beginning of this section.

The first three bullets are separate from the Inspection and Maintenance (I&M) Program described at the beginning of this section.

Feeder Hardening

This program was developed to specifically address overhead deteriorated equipment and lightning related interruptions on distribution feeders. These two causes are major drivers for distribution feeder reliability across the system. Asset replacement models are used to extract data from the reliability source systems related specifically to distribution line deteriorated overhead equipment, lightning and animal interruptions, respectively. This reliability data is combined with feeder asset data (overhead circuit miles) to create a framework to assess the performance of the feeder and determine the potential for reliability improvement through the Feeder Hardening Program. This process is in addition to the Inspection and Maintenance program.

The output of this modeling process is a ranked list of feeders (at least one feeder per region) which is updated annually to support the selection of feeders. This ranked list is reviewed and adjusted based on the expertise of division engineering groups. Recent significant changes or near-term planned changes to a selected feeder may impact its final selection.

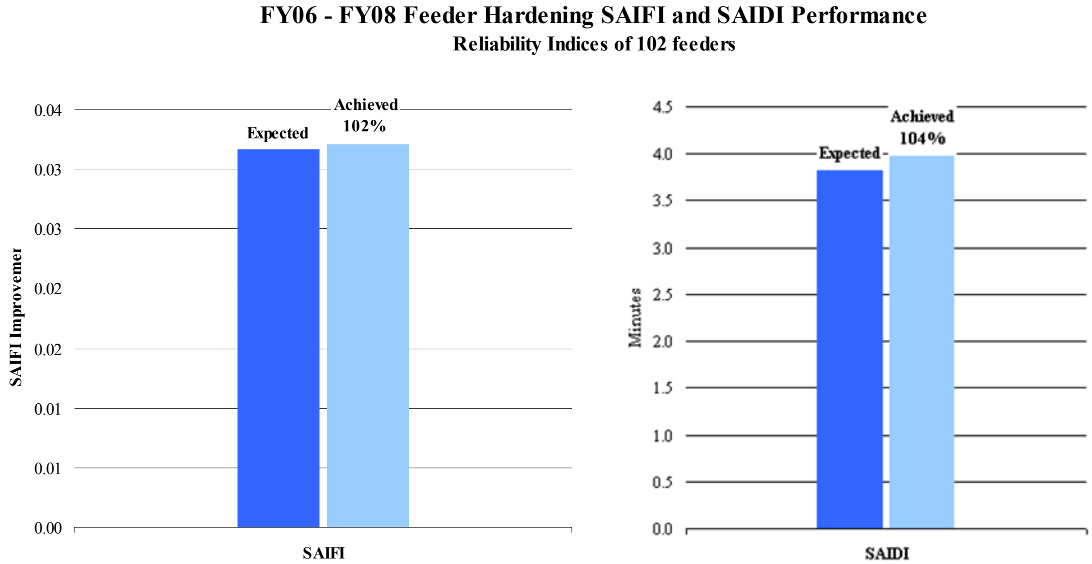
Next, the feeder is reviewed by Network Asset Planning for recloser/fusing opportunities, the ‘mainline’ undergoes an infrared patrol and finally, the feeder is inspected per EOP D004. The engineering data and all of the Level 2 and 3 priority codes are collected and forwarded to the Distribution Design department to create work requests to be issued to the Operations Department. All level 1, 2 and 3 priority codes collected for feeder hardening circuits are completed in the same fiscal year the feeder was selected for review.

Remedial Actions Performed and Planned

The Company has completed 696 miles (as of August 2009) of feeder hardening thus far in FY10 (1,319 total miles planned for FY10). By March 31, 2010, the Company expects that 213 feeders will have been hardened, representing 6,409 circuit miles, or 18 percent of the system since inception of the program. This program is scheduled for completion at the end of FY11 due to the improvements made to the I&M Program beginning in FY09.

In addition, an analysis of 102 feeders previously completed for at least one year (FY07 and FY08 feeders evaluated at the end of FY09) have met their expected improvement in SAIFI, or 0.032 improvement. Figure III-25 illustrates the performance improvement.

Figure III-25
Feeder Hardening



Based upon analysis of the feeders that were hardened, their performance has improved consistent with the expectations set by the program.

Engineering Reliability Reviews

As discussed in the 2008 Asset Condition report, the Network Asset Planning group is responsible for generating the list of Worst Performing Feeders during the preparation of the Electric Service Reliability Report filed annually in accordance with Case 90-E-1119. The list of feeders includes outages associated with supply issues (transmission or substation) and excludes major storms. From the list, a small number of geographically diverse feeders are selected for an Engineering Reliability Review (ERR). Forty-five feeders are being reviewed in FY10. Each review includes:

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

Remedial Actions Performed and Planned

This review has been in place since FY07 with 225 feeders going through the process. To date, this program is responsible for the majority of the more than 460 recloser installations (up from 329 reported last year). There are an additional 169 planned for this fiscal year and 50 are currently in service. The program is also responsible for thousands of side tap fuses associated with the Reliability Enhancement Program (REP) over the past three years.

Distribution Automation

After an initial investigation of automation and communication technologies, National Grid began a targeted Distribution and Sub-Transmission pilot in 2008, with systems becoming operational in 2009. This is discussed in more detail in the Sub-Transmission section as the Sub-transmission automation pilot went into operation in 2009 and is already providing benefits.

The following circuits are targeted for distribution automation and are in the process of being tested and implemented:

- [redacted] (all are 15 kV)
- [redacted] (all are 15 kV)
- [redacted] tie

The circuits should be operational before the end of 2009.

D. Distribution and Sub-Transmission Substations

In this section, National Grid will describe those substations which contain Distribution or Sub-Transmission assets. The information presented here begins at the station level, specifically those being rebuilt or replaced, and then reviews individual assets.

Substation assets frequently have long lead times when ordered and require significant projects, in terms of expense, complexity and over extended time periods for replacement or refurbishment. Consequently, it is often more efficient as well as cost effective to review an entire substation. Further, where there are asset issues which indicate replacement as an option, National Grid reviews planning and capacity requirements to ensure that alternative solutions are evaluated – including system reconfiguration to retire a substation. Hence the asset strategies coordinate with system planning in order to develop an integrated system plan.

National Grid has 441 distribution substations. In some of the substations, the Company is beginning to see age related degradation in two asset areas:

- primary equipment
- secondary protection and control cabling insulation

Asset age, by itself, is not the sole criterion to assess the condition of a piece of substation equipment. In addition to age, other indicators that may directly affect condition include:

- the accumulated number of through faults seen by a transformer or breaker, which will directly impact the mechanical strength and viability of the transformer
- the number of operations a breaker has seen, which will contribute to wear on the moving parts and subsequent need for maintenance or refurbishment
- insulation degradation which may be accelerated through thermal effects and which is irreversible for paper insulation – a key component in many substation assets
- likely obsolescence and availability of spare parts and skills required to maintain or refurbish an asset – in many cases the original manufacturer no longer supplies the equipment or the design is no longer supported and is therefore obsolete.

A summary of the equipment types and populations for key substation assets is provided in Table III-82.

Table III-82
Substation Asset Inventory

Main Asset	Inventory
Substations	441
Circuit Breakers	4,106
Power Transformers	816
Batteries/Chargers	208
Surge Arresters	1,090
Sensing Devices	2,237
Voltage Regulators/Reactors	692
Capacitor Banks	58

Substation Inspections and Work Orders

Substation Visual and Operational Inspections (V&O's) are performed bi-monthly on each substation. V&O's are a form of preventative maintenance in that they are designed to detect and mitigate defects in substation equipment.

Table III-83 summarizes substation inspection data:

- Number of each type of work order per year
- V&O as initial inspections (work orders in their own right, but as data collection)
- FO as Follow On work, generated as proactive substation activity
- TM as Trouble Maintenance, generated as reactive work
- Days, on average, per work order completed per year
- Number of work orders of each type per station per year on average

Table III-83
Substation V&O, OF and TM Work Orders

Year	V&O annual count	V&O avge. days	V&O per station annually	FO annual count	FO avge. days	FO per station annually	TM annual count	TM avge. days	TM per station annually
2005	1,484	15.8	3.5	146	1.0	0.3	189	2.3	0.4
2006	2,977	18.2	7.0	328	1.2	0.8	708	2.8	1.7
2007	2,707	5.5	6.4	665	1.5	1.6	876	2.4	2.1
2008	2,744	1.1	6.4	898	4.1	2.1	701	1.6	1.6
2009	1,601	1.0	3.8	870	1.6	2.0	337	4.4	0.8

V&O activities have been performed on all National Grid substations since they were initiated in 2005. In general, as V&O inspections have been implemented:

- the amount of time for a V&O work order to be completed has declined, indicating increased facility with the approach and execution of the work order

- the number of V&O per station averages at just over six, indicating that the Company is generally inspecting every station as planned

- the number of Follow On work orders has increased reflecting a more proactive approach to substation maintenance

- the number of trouble maintenances has declined, reflecting a less reactive approach and reduced impact of unplanned equipment unavailability

Substation Equipment Assessments and Asset Condition Codes

A substation condition assessment approach has been initiated across all New York substations. This includes a regular visit to each station by a subject matter expert to review the condition of the assets. The result is a report which gives each asset a condition code of 1 through 4, with 1 being acceptable and becoming less acceptable the higher the number, based on manufacturer family, condition, age and other relevant data (Table III-84).

Manufacturer family evaluations are composed of historical "family" performance and engineering judgment and experience. The condition code can be further refined by a visual site survey performed on the specific assets and local input as to performance and maintenance history.

Aligned with the condition code is an impact code – higher numbers indicating higher impact as a result of failure – which combines with the condition code to provide a risk based framework for asset prioritization. As National Grid develops this approach, asset replacement and maintenance will be ranked based on condition, but prioritized based on risk.

Table III-84
Substation Condition Codes

Code	Classification/Condition	Implication
1 Proactive	Asset expected to operate as designed for more than 10 years	Appropriate maintenance performed; regular inspections performed
2 Proactive	Some asset deterioration or known type/design issues Obsolescence of equipment such that spares/replacement parts are not available System may require a different capability at asset location	Asset likely to be replaced or re-furbished in 5-10 years; increased resources may be required to maintain/operate assets
3 Proactive	Asset condition is such that there is an increased risk of failure Test and assessment identifies definite deterioration which is on going	Asset likely to be replaced or refurbished in less than 5 years; increased resources may be required to maintain/operate assets
4 Reactive	Asset has sudden and unexpected change in condition such that it is of immediate concern; this may be detected through routine diagnostics, including inspections, annual testing, maintenance or following an event	Testing and assessment required to determine whether the asset may be returned to service or may be allowed to continue in service. Following Engineering analysis the asset will be either recoded to 1-2-3 or removed from the system

. In subsequent sections of this report, condition codes are used to summarize the status of the asset type population.

Indoor Substations

National Grid has 26 [redacted] indoor 23 / 4.16kV indoor substations that were built in the 1920s through the 1940s which are targeted for replacement.

In last year's report we identified the main drivers behind the replacement of these [redacted] stations. These drivers are still relevant.

Actions Planned

A number of indoor station rebuilds are currently progressing. [redacted] Stations 29, 43 and 52's Bay #5 are built, 2 lineups of switchgear and most cable trays are installed as well as auxiliary equipment including panels, conduits, lighting, heating and battery chargers. Four transformers and a third lineup of switchgear need to be installed, tested and commissioned, and feeders converted to the new switchgear. [redacted] Bay #5 footer and base have been poured. Additionally, in May 2009, work was completed at [redacted]. This work consisted of a complete station replacement.

The table below provides details of the current status of the indoor substation replacement program.

Table III-85
Indoor Substation Replacement Program Status

Division	Substation Name	Preferred Solution	Alternative Option	Status Complete, In Progress Planned
Western	[redacted]	Rebuild in existing building	None	Complete
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	In Progress
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	Complete
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	In Progress
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	Complete
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	In Progress
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	Complete
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	Complete
Western		Rebuild station on adjacent property.	Rebuild Station at existing location	In Progress

Going forward, [redacted] are scheduled to be the next group of indoor substation rebuilds. The remaining population of indoor substations is currently being evaluated and a schedule is being drawn up for their replacement, which will likely result in two stations rebuilt per year.

Metal Clad Substations

Following last year's review of metalclad equipment based on V&O inspections and field assessments, further work has been performed to provide a better means to assess the condition of metal clad equipment based on electro-acoustic degradation parameters.[54] The initial review using this technique identified a number of locations where minor repairs or refurbishments were recommended. The review also identified another 22 substations (out of a total population of approximately 220 metalclad substations) that required major repairs or refurbishments. Accordingly, both the [redacted] substations are in the process of being replaced.

[54] A simple visual inspection does not pick up issues with hidden insulation or surface tracking effects. By using sensors to detect anomalous sound (acoustic) waves or electric signals in the metal clad it is possible to detect incipient failures before they reach a point where they become practical failures.

Metalclad equipment is prone to rusting and animal ingress which leads to moisture and dust related or animal related failures. V&O surveys help detect such degradation but do not identify poorly performing electrical equipment unless there is significant deterioration or failure - such identification being more likely with electro-acoustic detection techniques.

Condition and Performance Issues

A selection of 20 substations was analyzed with electro-acoustic techniques that detect partial discharges (PD), leading to identification of serious problems at [redacted] and [redacted] substations, with subsequent failure avoidance through preventative maintenance. Main contact burrs at [redacted] substation were repaired, and partial discharge from the R530 at [redacted] substation noted, with follow up required. Intermittent partial discharge at [redacted] substation will be pursued with further electrical partial discharge detection; a failure at [redacted] substation in June 2009 was unexpected, the station had been the subject of roof repairs in 2007.

Overall the use of the electrical partial discharge survey has been very beneficial, with two probable failures avoided, and deteriorated equipment detected with action plans for mitigation developed. The Company plans to survey metalclad equipment on a regular basis to provide base line information on the assets, with an ad hoc approach to individual cases involving suspect assets.

Table III-86 identifies those metalclad stations which are of most concern with respect to performance and risk mitigation.

Table III-86
Metalclad Substations with Performance Issues

Station ID	[redacted]	Watch
NY09-3140	[redacted]	PD detected on R530; need to follow up to identify degradation mode
NY09-1730	[redacted]	Poor condition with possible PD
NY09-2230	[redacted]	Replacement in progress
NY09-0930	[redacted]	Poor condition with possible PD
NY09-1530	[redacted]	PD related to main contact burrs detected and mitigated; follow up TEV required
NY08-5740	[redacted]	Replacement in progress
NY08-0140	[redacted]	Initial design begun
NY09-0100	[redacted]	Some rust, with a bus failure in 2008
NY08-4350	[redacted]	Replacement in progress based on condition
NY09-1320	[redacted]	Rusted throat connections and roof; due to be retired based on new 13.2kV feeder

These stations will be monitored through further electro-acoustic surveys, which will also be applied to other metal clad stations identified through the previous survey.

In addition to condition issues, planning and capacity studies have indicated that the [redacted] metal clad substation can be retired after feeder conversion at the station.

Actions Planned

Replacement of [redacted] metal clad stations has been initiated; [redacted] are at an initial planning stage while [redacted] is being engineered at present.

Further electro-acoustic surveys are planned to support on going preventative maintenance and V&O surveys as a proactive approach to condition based metal clad management is pursued.

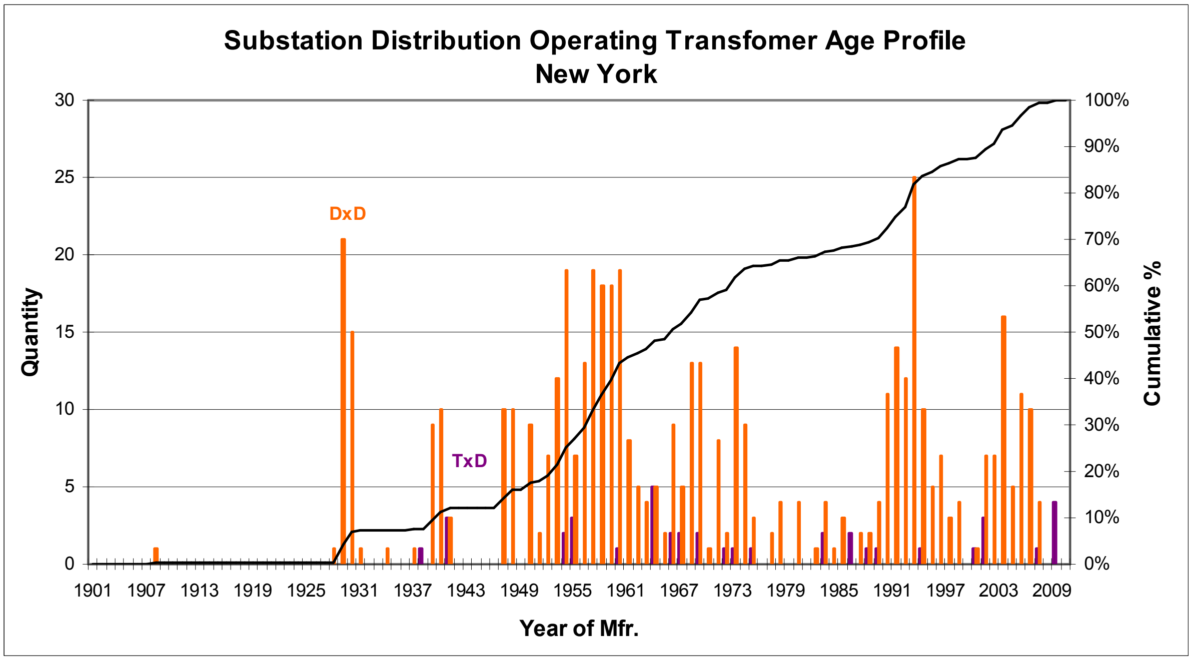
Power Transformers

National Grid has 816 distribution power transformers, plus 21 spares. The population of power transformers is generally sound, with some exceptions discussed in this section. The number of transformers is lower than the count provided last year, relating to a stricter counting procedure, removing a number of station service transformers, spare transformers and removal from the system of a number of single phase units replaced with three phase units. Power transformers range in size from less than 1 MVA[55] to about 20 MVA and may have several different MVA ratings depending on available cooling options – pumps for oil circulation and fans to assist with heat transfer.

The average age of the distribution power transformer population is 34 years, which is displayed in Figure III-26. There are 216 power transformers greater than 50 years of age based on nameplate data stored in the AIMMS database.[56] However, 32 percent of transformers have no year of manufacture indicated in the AIMMS[57] database at present, which implies that there are probably a further 260 units greater than 50 years of age.

[55] Mega Volt Amp – an indication of the maximum power, or load, which may flow through a transformer; MVA is given on the transformer nameplate as a rating for the transformer. Larger MVA transformers also tend to be physically larger units serving larger loads.
[56] Asset Information and Maintenance Management System
[57] Older transformers, pre 1950, often did not have the year of manufacture stamped on the nameplate. Those units without age tend, therefore, to be the older units.

Figure III-26.
Age Profile of Transformers



Power transformer age, by itself, is a useful proxy to indicate which transformers may be less able to perform their function through accumulated deterioration. Power transformer paper insulation, in particular, deteriorates (degrades) with time and thermal history. The deterioration is cumulative and irreversible and thus cannot be addressed via maintenance. As the paper degrades, the ability of the paper insulation to withstand mechanical forces is reduced and thus the mechanical integrity of the transformer is compromised in the face of through or internally generated faults. In addition, the paper deterioration may lead to shrinkage of the winding packs which are clamped in place, reducing the effectiveness of the clamping and, once again, reducing the mechanical stability of the transformer.

Given the possibly substantial impact of power transformer failures on the distribution system, and the extensive lead times and disruption to normal operations, National Grid pursues a comprehensive approach to risk management of transformers. This includes thorough and regular reviews of the population and the generation of a ‘watch list’ of suspect and higher impact transformers for more frequent observation and review. National Grid also reviews each transformer individually to determine both condition and likely risks to the system before making a determination as regards to replacement or refurbishment requirements.

Condition and Performance Issues

Distribution power transformers are assessed through Dissolved Gas Analysis (DGA) and a subsequent test and assessment approach to asset condition coding and ranking with significant input from subject matter experts.

It is National Grid's maintenance practice to perform DGA on distribution transformers rated 2.5 MVA to 15 MVA on a bi-annual basis and units rated above 15 MVA on an annual basis. In addition, DGA may be performed more frequently on suspect units to monitor the condition more closely, as happens with transformers which are being closely monitored, and sampling and analysis may be quarterly, monthly or more often. This information is used to determine the current condition of the transformers and the likely degradation over time.

Table III-87 provides last year's condition codes and the current condition codes based on this review. This year, six transformers were placed as condition code 4. Due to elevated gasses, poor insulation test results, inadequate thermal capability[58] and no known available spares, these six transformers were coded as condition code 4. In addition, these units are mature in age and may be better served being replaced rather than maintained or repaired. In comparison to last year, five small single-phase transformers were added to condition code 3 based on field and engineering experience related to operational problems, poor condition and excessive age of the units. Approximately eleven units were added to condition code 2 due to similar issues and to align with the Company's transformer risk and condition review.

Table III-87.
Condition Code of Transformers

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

It should be noted that placing a transformer into condition code 4 does not automatically trigger a replacement; the transformer may be placed on more frequent DGA sampling and analysis and subsequent review. It is likely that code 4 units will subsequently be revised to a lower condition code but it is possible that they will be replaced.

Transformer failures, by their nature, are inevitable but National Grid's aim is to minimize the likelihood of failures caused both by:

- Internal events – insulation failure, winding movement etc.
- External events – through faults, lightning, animal incursions etc.

Incipient internal deterioration may be detected through DGA, Visual & Operational Inspections, Infrared inspections, PIW's or identified through engineering and industry knowledge. External events are addressed through application of lightning arresters, animal protection and through pursuit of such activities as Feeder Hardening and Vegetation Management.

[58] Transformers are designed to operate at certain thermal temperatures. If a unit is heavily loaded, this may exceed its thermal capability.

Actions Performed and Planned

There were 15 transformers identified in the "watch list" in the 2008 Asset Condition Report. The watch list is a tactical response to power transformer condition based on condition and operational information. Where a transformer is subject to a through fault, as may be initiated by a lightning strike, it may:

- fail instantaneously, as a result of internal stresses generated by the through fault
- may start to deteriorate, with deterioration as a result of through faults accumulating and weakening the transformer over time
- may generate diagnostic gases, detectable through DGA, which provide valuable data in determining likely degradation
- may generate gases which subsequently stabilize.

The watch list is used to monitor those transformers which are 'of concern' to assess how their condition develops, and if need be, plan for rapid replacement of the unit.

Of the 15 units identified in the 2008 Report:

Three transformers at [redacted] Station were retired due to condition; they were removed from the system in a controlled manner to avoid possible failure

- The unit at [redacted] failed unexpectedly, having been stable for a short period. The failure triggered an action plan that involved running the remaining two single phase units to continue to supply load while a mobile unit was brought into position. Subsequent replacement of all three units with replacement transformers was undertaken and completed in March 2009.
- Two units, [redacted] and [redacted] were removed from the list due to stable DGA results, condition assessments and review by Company experts
- Six transformers [redacted]) were removed from list after they were reviewed and showed either stable and non-volatile DGA results or improving DGA results and were assessed as being unlikely to deteriorate rapidly or fail unexpectedly. These six units remain on the Company's fifteen-year replacement list in accordance with the revised Distribution Substation Transformer Strategy.

Three units remain on the present list: [redacted]:

- the [redacted] unit has high hydrogen and moisture in the DGA but is stable, is being monitored and is under more frequent DGA analysis; the station is due to be retired but the units remain under observation

- the [redacted] unit has high hydrogen in the DGA but is otherwise stable. Though installed in 1996 the unit is older and was transferred from another station

- the [redacted] unit shows signs of some overheating or a hot-spot within the transformer, diagnosed from higher than normal levels of ethylene in the DGA

  - Each of these units is on increased frequency for DGA and assessment and a mobile has been identified for application if necessary.
  - It should be noted that [redacted], Transformer No. 2 has been removed from the system due to condition in 2009 and is in the process of being replaced.

The latest transformer review identified 22 transformers to watch due to elevated DGA's and some associated risk. A review of possible transformer spares and mobile capability is planned for the transformers on the list. In addition, the ability to perform field ties and single-bank units with Delta high side windings[59] are reviewed for a possible solution if a problem arises. An increase in DGA sampling will occur where needed to closely monitor the transformer condition. Table III-88 provides the list of the top 22 transformers that are on the "watch list".

[59] The three high voltage windings are connected in a delta formation rather than a grounded wye formation.

Table III-88.
List of Distribution Transformers on "Watch"

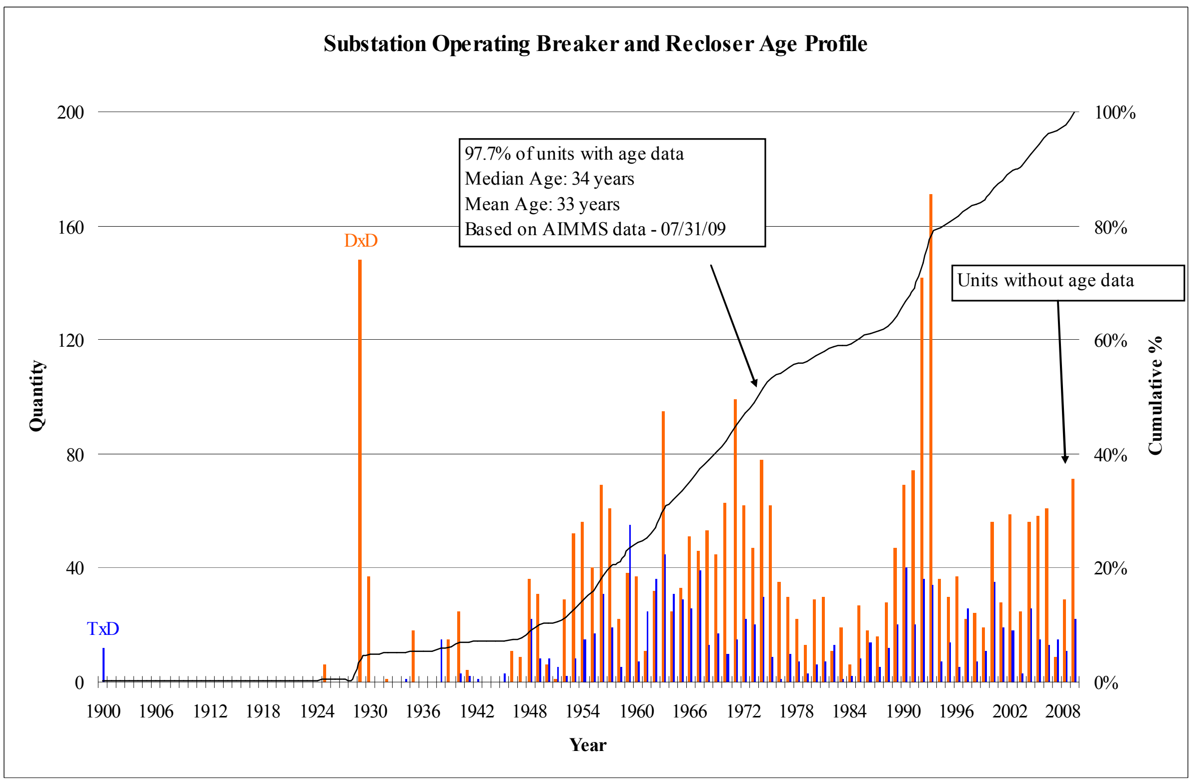
STA LOC	MVA	VOLT	AGE	Mfr	Condition Code
[redacted]	6.25	34-13.8kV	39	WE	4
[redacted]	6.25	34.5-2.4 kV 5/6.25 MVA	52	GE	4
[redacted]	3.75	34.5-13.8 kV 3.75 MVA	36	NIAG	4
[redacted]	3.75	34.5-4.16 kV 3.75 MVA		PENN	4
[redacted]	5.25	34.5-4.16 kV 5.25 MVA		WE	3
[redacted]	4.687	34.5-4.16 kV 4.687 MVA		WE	3
[redacted]	3.75	23-4.8 kV 3/3.75 MVA	55	GE	3
[redacted]	3.75	23-4.8 kV 3/3.75 MVA	55	GE	3
[redacted]	6.25	34.5-4.16 kV 5/6.25 MVA	49	A-C	4
[redacted]	2.5	23-4.16 kV 2.5 MVA	79	WE	2
[redacted]	3.75	34.5-4.8 kV 3.75 MVA	49	MGED	3
[redacted]	5.6	34.5-4.16 kV 5/5.6 MVA		MGED	3
[redacted]	7	46-4.16 kV 5.6/7 MVA	55	WE	4
[redacted]	2.5	34.5-4.8 kV 2.5 MVA		GE	3
[redacted]	3	34.5-4.16 kV 3/3.65 MVA	52	GE	3
[redacted]	2	34.5-4.16 kV 2 MVA	80		3
[redacted]	2	34.5-4.16 kV 2 MVA	80		3
[redacted]	2	34.5-4.16 kV 2 MVA	80		3
[redacted]	2	34.5-4.16 kV 2 MVA	80		3
[redacted]	2	34.5-4.16 kV 2 MVA	80		3
[redacted]	2	34.5-4.16 kV 2 MVA	80		3
[redacted]	10.5	34.5-13.8 kV 7.5/9.3/10.5 MVA		GE	3

Programs are in place to replace substation power transformers. All 22 transformers on the 'watch list' are on the Company's five-year replacement list. However, the five-year list may be adjusted due to changes in transformer condition and quarterly reviews. Although transformer replacements are based on condition, a cautious approach based on the end of useful life is used to determine the appropriate number of transformers needing replacement on a per year basis.

Circuit Breakers

National Grid has 4,106 circuit breakers (4,053 operating and 53 spares) on the distribution system, with an average age of 33 years (Figure III-27). The substation circuit breaker population is generally sound and reliable, but there are certain units which will be addressed as described below.

Figure III-27
Age Profile of Circuit Breakers



There are relatively few gas circuit breakers (GCB) in the breaker population, but similar numbers of Air Magnetic Circuit Breakers (AMCB), Oil Circuit Breakers (OCB) and Vacuum Circuit Breakers (VCB) as shown in Table III-89. This analysis of breakers includes breakers, reclosers and switches.

Table III-89
Breakers Types

Breaker Type	Percentage of Total Population 2008	Percentage of Total Population 2009
AMCB	28.0%	27.6%
GCB	3.5%	3.5%
OCB	31.5%	31.2%
VCB	37.0%	37.7%

Older breakers though inherently not less reliable due to age, are more difficult to maintain, may not meet the specifications needed for modern electrical systems and may have no support in terms of replacements or spare parts.

The approach for breaker condition coding was based on engineering judgment and experience and was supported by discussion with local field staff. Additionally, field information has been gathered through the Problem Identification Worksheet (PIW) system. Data entered into the PIW system supports the identification of assets in need of maintenance and/or replacement. Condition codes have been applied to the operating population as shown in Table III-90.

Table III-90
Condition Code of Circuit Breakers

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

The reduction in code 4 breakers is based on an engineering review of the breaker population with subject matter experts in conjunction with a review of relevant Problem Identification Worksheets (PIW's) and interruption data. The increase in Code 3 breakers reflects a cautious approach to particular asset families, described below. The change in total breaker population is a result of a complete review of the asset group and additions/removals to population due to construction.

On-going breaker maintenance and inspection generates further knowledge and understanding of breaker condition. The process of reviewing and rating breakers is continual and is supported by an initiative to audit data quality and update data through substation data collection and asset condition assessment during maintenance activities.

Five-year average SIR[60] data shows approximately 20 substation events related to breakers each year with an average of 12,000 customers interrupted and 1.5 million customer

[60] SIR – System Interruption Reporting, data which relates to customer interruptions reported for reliability purposes and recorded in the SIR system

minutes interrupted. This equates to a SAIFI of 0.007, SAIDI of 0.96 minutes and a CAIDI of 130.6 minutes.

Actions Performed and Planned

Sixty-nine breakers were added to the system and approximately 180 breakers were decommissioned in 2008. Nine breakers have been added to the system (through the end of July) and approximately 70 were decommissioned thus far in 2009.

Seventeen circuit breakers are scheduled for replacement in FY 2010 as part of a one for one replacement program. In addition to these one for one replacements more breakers will be replaced and/or decommissioned at locations involved in either substation rebuilds (Buffalo indoor and metalclads) or retirements.

Due to either obsolescence or poor performance, condition codes 2 and 3 breakers in the families listed in Table III-91 are targeted for replacement/refurbishment over the next ten years. The breaker families were reviewed during a revision of the breaker strategy with slight changes in targeted families. This review resulted in the addition of two targeted families to the group and the removal of two families. Additionally, the quantities have been updated.

Table III-91
Circuit Breakers to be Replaced/Refurbished

Type or Family	Quantity	Average Age (Years)
Condit (code 3)	40	82
Federal Pacific (code 3)	28	48
General Electric Type AM (9 - code 2, 7 code 3)	16	43
General Electric Type VIR (code 3)	4	33
ITE Type HK (73 - code 2, 84 code 3)	157	36
ITE Type KS (code 2)	56	40
McGraw-Edison Type VSA (code 2)	2	21
Westinghouse Type DHP (code 2)	77	35

Capital programs are in place to address circuit breaker replacements.

Protection and Controls

Relays

Since the last asset condition filing, significant progress has been made in entering the historical records for the relay population into an electronic system for easy retrieval. Once complete, electronic records will improve audit response and relay data management.

Currently a project to enter all the data into the Asset Database is approximately 75 percent complete.

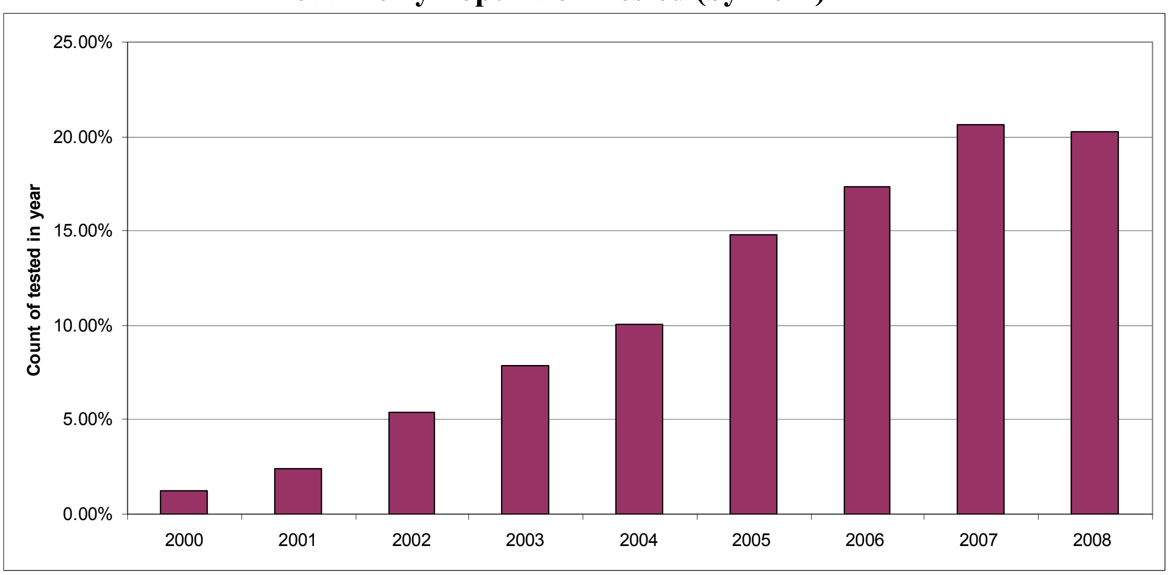
The following table indicates the number and type of relays currently installed on the Sub Transmission/Distribution network (these numbers may change once the data migration exercise is completed).

Table III-92
Sub-Transmission and Distribution Relays

Class	Inventory
Electromechanical	12,113
Microprocessor	1,638
Solid State	400

The following graph shows that National Grid is testing approximately 20 percent of the relay population each year. This is a significant improvement over the testing rates from a few years ago. The testing frequencies for relays are not all the same, but depend on the type of device. When a relay is tested and fails, then it will either be repaired where possible or replaced.

Figure III-28
Total Relay Population Tested (by Year)



Many of the in-service relay systems are of the older electro-mechanical type that does not support modern fault recording and analysis. For example, they may indicate a fault on a B-phase conductor. A modern digital fault recorder (DFR) will record the phase, location, fault type, condition of the power system at the time and oscillographic records for detailed analysis. Moreover, a number of relays are no longer supported by the manufacturer, replacement parts are no longer available and knowledge of their operation both internally and externally is nearly nonexistent.

Actions Planned

Relays are unlike high voltage equipment which wears out in somewhat predictable and observable way. The only way to detect a problem is through routine tests or if the relay fails. The substandard technical performance of some relays has significant negative effects on the secure and reliable operation of the system under today's increasing load demands and stresses.

National Grid will be conducting a comprehensive assessment of existing protective relaying and substation control systems. This will be followed by a two stage forward-looking technical strategy for the replacement program. The plan will not only meet the current requirements, but also allow flexibility in order to be able to adapt to changes in the technology or needed functionality. Replacing Protection and Control Systems as a whole has advantages over an uncoordinated component replacement approach. As the majority of the systems are old, several components are nearing their end of life such as relays and control cables. Replacing the entire system at the substation allows for the full use of the functionality that today's multi function microprocessor based relays can offer, as a whole substation solution while at the same time reducing the overall cost. Taking advantage of emerging technology will reduce the amount of copper wiring and the number of components in the systems. This new architecture will reduce the footprint of the Protection and Control room and allow easier future replacements with minimum outage requirements

The new protection relays and other substation automations will support IEC 61850, which provides interoperability between multiple devices from different manufacturers applied at different levels of the substation system. The devices can connect directly to the substation local area network using optical fibers. The data collecting, control, and protective communications among the relays will be implemented via an internal local area network (LAN). Dedicated hard control wiring and panel controls can then be eliminated. The upgraded system will provide modern physical and cyber security capabilities and allow the integration of an efficient array of protection, control, and monitoring apparatus to meet new technical and economic challenges.

For the short term (next two to five years), the relay types and the associated relay packages to be replaced will be identified on the following factors: (1) feedback from the field work force and information on obsolescence received from manufacturers; (2) priority criteria, which will be based on the installation location, failure mode, risk to system, reliability, and customer impact. (3) relays for some specific circuits or equipment with operating issues and relaying problems.

Generally, the replacement plan will be implemented on a line-by-line basis. In some existing stations, if the control room is in poor condition or can not meet present requirements, such as limited space available for future expansion and new panels, not meeting fire protection and security code, structural infirmity, poor HVAC performance for relays then a new control room may be required. In this case, all the relay packages installed in the old control room will be updated and replaced.

In some occasions, a station rebuild may be necessary. In such cases, the control room and all associated protection packages will be replaced as part of the rebuild. In order to achieve better co-ordination and performance, the counterpart relay packages on the other end of the line will be evaluated for replacement at the same time. The existing relay packages will remain in service until the replacement is complete. An assessment of the condition secondary cabling shall be completed at the same to make sure it complies with the relevant IEEE and IEC standards. The replacement of secondary cabling may be initiated if the present condition warrants replacement.

In the longer term (beyond five years), there will be two categories of replacements, one for relay packages only and another for the whole control room. The relay package upgrade will be conducted within the existing control building. The relay package for a particular line or equipment will be identified and the scope of work will be defined carefully to minimize the impact on the operational system. During a planned outage, the old protection panels will be removed from their location to avoid confusion and a new panel will be installed.

The project implementation plan for control room replacement includes a pilot phase, followed by large scale phase. A pilot project will be implemented to control risk and demonstrate results for the future replacement. The new control room will be pre-built, pre-wired and pre-tested, with confirmation that all of the project requirements are met. The optical fiber will be the main communication channel. The control room can be shipped to the site and all external cabling will be connected during the planned station outage. Subsequent control room replacement plans will gain from experiences in the pilot project.

National Grid has and will continue to assess the relay protection systems on the distribution and sub transmission systems and adjust, upgrade, and/or replace protection and control system as needed to ensure the reliable operation of the network. The strategy plan will be reviewed and updated annually according to a comprehensive annual asset health review. The recommendations of next year's relay replacement plans will take into account any new problem relays or issues.

National Grid is developing a strategy to address relay data.

Substation SCADA (Substation Control & Data Acquisition) & Remote Terminal Units (RTUs)

SCADA (Substation Control & Data Acquisition)

Currently approximately 72 percent of the New York substations have SCADA. The total number of stations that need SCADA in New York is estimated to be approximately 160. SCADA systems, when used to monitor and control the distribution feeder breakers, can provide a 15 percent to 20 percent reduction in average customer outage duration (CAIDI) when compared with a similar feeder that is not equipped with SCADA facilities. This reduction in outage time results primarily from the dispatcher being informed immediately of a switch operation and taking action before customers call to report the outage. SCADA systems can also provide the dispatcher with fault location clues that can help reduce feeder patrol time. Substation SCADA systems additionally provide system operators with immediate notification when an interruption occurs within a substation, so that service restoration activities can start immediately. Substation intelligent electronic devices (IEDs) can also provide an estimated fault location, which can significantly cut feeder patrol times.

The priority for providing SCADA is based on substation loading, importance of the station related to customers served as well as impact the loss of this station has on the system, frequency of times that switching is done at the stations, stations that support the sub-transmission, substation status, metering and control that would be most advantageous to regional control operators based on historical experience, mitigating customer outages or improving system integrity, the number of customers affected by outages/interruptions, the past fault/outage frequency and severity for a given area, as well as the customer sensitivity to outages in a given area.

Remote Terminal Units (RTUs)

The RTU equipment at many New York substations is obsolete and in most cases unsupported by the manufacturer. Replacement parts are either difficult to obtain or unavailable. The equipment does not have and cannot be modified to provide the capabilities required for modem supervisory control and data acquisition. New equipment will facilitate remote maintenance and diagnostics saving time and expenses associated with maintaining the equipment. The new RTU's will be compatible with any replacement EMS systems currently envisioned in New York.

Actions Planned

National Grid is currently developing the program which will install remote terminal unit (RTU), wiring, control, and data acquisition capability on the equipment at the substations listed below during FY2009 and FY2010.

[redacted]

Batteries and Chargers

Substation batteries and chargers play a significant role in the safe and reliable operation of the substation. Batteries and chargers provide DC power for protection, control and communications within the substation and between substations and control centers.

Battery systems on each substation are checked for leaks and degradation during bimonthly V&O inspections. An annual test of each battery system is performed to confirm condition.

National Grid Substation Maintenance Standards identify the expected life of substations batteries and chargers as twenty years; this is in line with industry expectations and manufacturer guidelines. As with previous years, there are 11 different standards which apply to batteries and chargers. National Grid also issues maintenance bulletins relating to specific battery types where individual cells have an increased rate of deterioration or impaired performance.

The current population of batteries is in sound condition; where a battery system has reached the end of its expected life it is reviewed for capacity and may be given a life extension.

Table III-93 provides current condition codes for the battery population.

Table III-93.
Condition of Battery Population

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

Actions Planned

A program to replace battery systems on condition or at end of asset life as per National Grid standards is in place. Where possible, the battery charger is replaced at the same time as the battery system.

Other Substation Assets

Assets described here would be addressed individually should their condition dictate a rapid response, or while addressing maintenance, replacement or refurbishment ongoing at the same station.

Power Transformer and Circuit Breaker General Electric Type U Bushings

The bushing population is sound and reviewed regularly as part of ongoing maintenance and inspection cycles. Infrared inspections are performed yearly and visual and operation inspections are performed every other month. However, GE Type U bushings have a known failure mode due to insulation degradation, which can be catastrophic, and they are a risk to both safety and the system. This problem is known and understood within the industry The problem may be detected through Doble power factor measurements[61], which are standard in the industry and within National Grid.

Also, National Grid has occasional problems relating to type U bushings and has developed a Substation Maintenance Standard, SMS 450.20.1 (10) to address this issue. This standard also addresses problems with top terminal overheating in GE Type U and ABB O + C bushings. In addition, manufacturer service advisories are updated and evaluated to keep abreast on issues associated with specific bushing types.

Substation Structures and Foundations

Substation structures are inspected as part of V&O routine checks and through the PIW process. Defects are prioritized and repaired or replaced as necessary.

Generally substation structures are sound, but some significant issues at particular stations may be found and require remedial action.

Surge Arresters

Surge arresters are monitored during routine V&O inspections, diagnostic inspections and annual infrared surveys. Arresters on transformers rated greater than 15 MVA are tested when the transformer is taken out for maintenance in line with substation maintenance standards. Arresters on transformers rated less than 15 MVA are tested only if identified through V&O or infrared surveys.

National Grid's strategy is to remove less reliable Silicon Carbide (SiC) surge arresters from substations. Replacements are made during substation transformer maintenance, transformer replacement, and transformer relocations; replacement of the arresters then takes place in line with current substation maintenance standards and procedures.

There are no particular issues with relation to surge arresters on National Grid substations. A recent study showed that failure rates were in line with industry norms and SiC arresters were not unduly prominent in those failures.

Cap-Pin Insulators

Insulators are used to block current flow and provide support for substation bus work and other structures. Cap-Pin insulators are a known industry problem, being less reliable than other forms of insulators leading to interruptions. National Grid identifies problem insulators through regular substation V&O inspections, PIW submissions and replaces them where they are identified as a risk, or as part of on going work at a particular substation, in line with current Substation Maintenance Standards and Procedures.

The failure of a cap-pin insulator may result in an extensive interruption as the insulators are frequently related to main bus installations. However, many thousands are in service

[61] Standard tests to measure power factor, or tangent delta, of insulation is known, generally, as a Doble test

which do not provide any disruption and the present policy of changing out insulators based on condition or while addressing other asset conditions at the station, is adequate.

Sensing Devices

The term sensing devices is used to cover current transformers (CTs) and Voltage Transformers (VTs) / Potential Transformers (PTs). As indicated in Table III-94 below, the population of sensing devices has remained fairly static at approximately 2240 units, which are generally in good condition.

Table III-94.
Condition Codes of Sensing Devices

TYPE	1	2	3	4	Grand Total
2008	1,655	586	0	0	2,241
2009	1,651	586	0	0	2,237

Capacitor Banks and Switches

A capacitor is an electrical component that stores energy (charge) in the form of an electrostatic field. Capacitors are used to maintain voltage levels and improve electrical-system efficiency (power factor). Ideally, substation capacitors are used to compensate for power transformer reactive losses. A vacuum switch (fault interrupter) is a switching device that utilizes vacuum modules to interrupt current.

V&O inspection of capacitor banks is performed every two months according to the substation maintenance standard. In addition to the V&O inspection, an annual infrared inspection is performed along with a pre-peak inspection each spring, including checks of the bank switching device.

Capacitor bank switches of Joslyn vacuum design are known to have occasional failures and are replaced on a case by case basis (they do not significantly impact reliability and are generally held in stock) and are known to not fail catastrophically.

Table III-95 provides the distribution capacitor bank population, showing that the bulk of the population is in good condition. No new banks have been installed since the last report.

Table III-95.
Capacitor Bank Condition Code

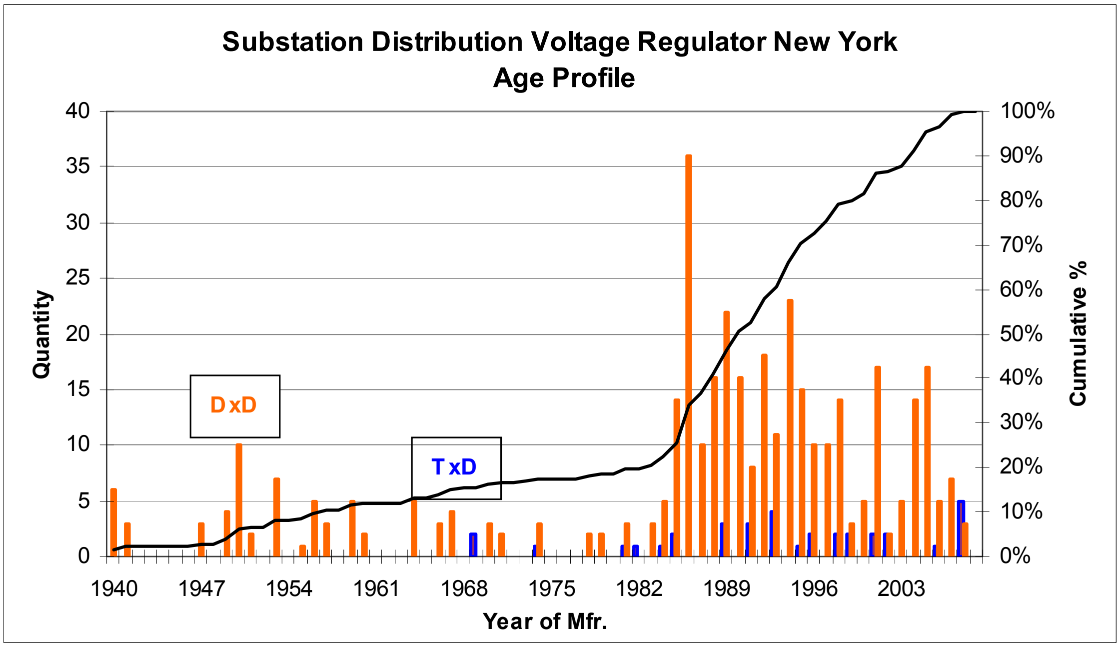
TYPE	1	2	3	4	Grand Total
CAP	55	3	0	0	58

Reactors and Regulators

Regulators and reactors provide voltage control and power flow management capability. National Grid has approximately 672 regulators, and 66 spares. The average age of the operating regulator population is 22 years, with 4 percent of the population being greater than

60 years old, and the majority of the units are less than 24 years old. The regulator age profile is found in Figure III-29 below.

Figure III-29
New York Regulator Age Profile



There are approximately 20 air-core substation reactors. Eight are two years old and the remaining reactors are much older, but are missing age data information. In the early years, manufacturers did not provide manufacture dates on their nameplates. In addition, reactors with a concrete base tend to be more than 40 years old.

Condition and Performance Issues

Regulators of specific manufacturer and design are considered to be less reliable and are listed in Table III-96. There has been a high failure rate of Siemens JFR regulators purchased between 1988 and 1993. The most common failure mode is burning and failure of the moveable or stationary contacts. The General Electric IRS and IRT Induction regulators and the Westinghouse IRT regulators have known switching problems, parts are obsolete, and are unlikely to sustain a through fault when compared to more modern type regulators. Air core reactors rated 23 kV at [redacted] in Buffalo have deteriorating concrete bases that are addressed through the [redacted] reactor program. Two Siemens, Type SFR, three-phase regulators manufactured in the 1960s have failed and will be replaced with new units. There are two more of these units remaining and plans are being made to purchase spares.

Voltage regulators are a stores item that are monitored via V&O inspections and infrared surveys. Other problematic regulators may be identified from these inspections and PIW submission.

Table III-96.
Voltage Regulator Types

Manufacturer	Type	Count
Siemens	JFR	11
GE	IRS/IRT	94[62]
Westinghouse	IRT	0

Air-cooled reactors are monitored via V&O inspections and infrared surveys. Older concrete base type reactors are problematic but do not result in adverse reliability consequences. Replacement of these reactors will be based on condition, age and opportunity. Table III-97 summarizes asset conditions for regulators and reactors.

Table III-97.
Condition Code of Regulators and Reactors

TYPE	1	2	3	4	Grand Total
VREG	487	183	0	2	672
REAC	20	0	0	0	20

Regulator failures will result in customer outages, and regulator or reactor problems may lead to fluctuations in voltage.

<u>Actions Performed and Planned</u>

Step voltage regulators, which are considered modern, are maintained in accordance with SMS 404.01.1 Step Voltage Regulator. Induction voltage regulators are maintained in accordance with SMS 404.02.1 Induction Voltage Regulator. In addition, there is SMS 404.40.1 Siemens JFR Regulator Replacement and SMS 404.40.2 GE IRS/IRT Voltage Regulator Replacement which cover replacement of those two voltage regulator types. A Substation Voltage Regulator Strategy has been approved and regulators have been identified for replacement as a result. Pursuant to this strategy, ten modern type regulators have been added to the system within the last year, and approximately 72 regulators have been retired. Two units have failed and will be replaced.

A Reactor (Non-transformer) Strategy has also been approved. The reactor count has changed slightly from last year due to entry of older units into our substation database.

Problematic voltage regulators have been identified and a replacement plan is on-going in accordance with the Voltage Regulator Strategy, the above mentioned Substation Maintenance Standards and on-going maintenance activities.

The air core reactors located at [redacted] Substation have concrete frames that are deteriorating and breaking apart, and since the coils are wound around the frame, this weakens their condition and may cause a problem if a system disturbance occurs. There is a program in place to replace these nine reactors.

[62] Westinghouse IRT is the same design as the General Electric IRT

IV. EXHIBITS

The following pages contain the exhibits referenced in the Report.

[redacted]

Exhibit 2.

Comprehensive review of the New Scotland – Leeds – pleasant valley Transmission corridor

A detailed condition assessment report on the New Scotland – Leeds – Pleasant Valley transmission corridor, which is a key transmission corridor that facilitates considerable transfer capability between New York's upstate and downstate transmission system, was recently completed. This report reviewed a variety of dimensions that impact this corridor's reliability performance, such as:

- Opportunities for reducing exposure to cascading structure failure
- Opportunities for reducing the number of transmission crossings
- Tensile and torsional ductility tests on phase conductors
- Assessment of lightning performance
- Wind analysis to determine whether the current design criteria is still valid

The recommendations from this report are summarized below:

- New Scotland Substation

[redacted]

- Leeds Substation

[redacted]

Exhibit 2 (Continued).

[redacted]

Exhibit 2 (Continued).

[redacted]

Exhibit 3.

Priority Codes

Priority Code	Required Response
Level 1	Problem must be repaired/addressed within one week
Level 2	Problem must be repaired/addressed within one year
Level 3	Problem must be repaired/addressed within three years
Level 4	Problem information is used to plan future work but does not need immediate attention.

Exhibit 4

345kV HPFF Circuits – [redacted] Description		Item Id	Qty	Physical Location	Strategic Spares
Splices	• 345kV HPFF 3 phase Repair Joint w/ 10" split sleeve 1/C-2500kcmil Cu, 0.920" paper insulation	9201135	0	[redacted]	Transition between E105/F106 cable & Conklin Bailey
	• 345kV HPFF 3 phase repair Joint w/ 8" & 10" split sleeve 1/C-2500kcmil Cu 0.920" paper to 1/C-2750kcmil Cu 0.600" LPP	9201682	2		To be ordered.
Terminations	• 345kV, HPFF Ohio Brass Outdoor Termination • 1/C-2500kcmil Cu, 0.920" paper insulation • (Consumables only – no porcelain)	9201137	3		3 termination consumables

230kV HPFF Circuits – [redacted] Description		Item Id	Qty	Physical Location	Strategic Spares
Cable	• 1/C-2500kcmil segmental Al, 0.620" paper insulation, 230kV HPFF • (lead sheath on reel)	• 9201117	• 1000'	[redacted]	•
	• 1/C-1500kcmil segmental Cu, 0.835" paper insulation, 230kV HPFF • (lead sheath on reel)	• 9201122	• 350'		•
	• 1/C-750kcmil Cu, 0.835" paper insulation, 230kV HPFF • (lead sheath on reel)	• 9201121	• 268'		•
Splices	• 230kV HPFF three phase repair joint – no split sleeves • 1/C-2500kcmil AL, 0.620" paper insulation • (intent is to use split sleeves from Item # 9201358)	• 9201307	• 2		• 2 - 3 phase • repair splices
	• 230kV HPFF three phase repair joint – no split sleeves • 1/C-1500kcmil Cu, 0.835" paper insulation	• 9201134	• 2		• 2 - 3 phase • repair splice

Terminations	• (also has connectors for 1/C-750kcmil Cu)			[redacted]	
	• 230kV HPFF split sleeves, spiders & pipe adapters for 8" steel pipe	• 9201358	• 2	[redacted]	2 repair sleeves
	• 230kV HPFF Outdoor Termination Porcelains and Spools	• 9201139	• 5	[redacted]	5 porcelains
	• 230kV HPFF Outdoor Termination Consumables Kit • 1/C-750kcmil Cu or 1/C-1500kcmil Cu, 0.835" paper	• 9201308	• 5	[redacted]	5 consumables
	• 230kV HPFF Outdoor Termination Consumables • 1/C-2500kcmil Al, 0.620" paper insulation	• 9201309	• 3	[redacted]	3 consumables
230kV LPFF Circuits – [redacted] Description		Item Id	Qty	[redacted]	Strategic Spares
Terminations	• 230kV LPFF Outdoor termination • 400kcmil Cu, 0.835" paper insulation, fluted lead sheath cable • (complete kit)	• n/a	• 1	[redacted]	1 termination
115kV HPFF Circuits - [redacted]					
• Description		• Item Id	• Qty	[redacted]	Strategic Spares
• Cable	• 1/C-1750kcmil segmental Cu, 0.420" paper insulation, 115kV HPFF • (lead sheath on reel)	• 9201128	• 350'	[redacted]	Short piece out
	• 1/C-1250kcmil Cu, 0.435" paper insulation, 115kV HPFF • (lead sheath on reel)	• 9201124	• 350'	[redacted]	Short piece out
	• 1/C-1750kcmil segmental Cu, 0.375" paper insulation, 115kV HPFF (lead sheath on reel)	• 9201683	• 1575'	[redacted]	Universal Spare – 1reel longest length
• Splices	• 115kV HPFF three phase repair joint w/ split sleeve for 10" pipe • 1/C-1250kcmil Cu, 0.435" paper insulation	• 9201306	• 2	[redacted]	2 joints
	• 115kV HPFF three phase repair joint w/ split sleeve for 6" pipe • 1/C-1750kcmil Cu,	• 9201133	• 2	[redacted]	Connectors and Templates, but no

	• 0.435” paper insulation (also contains connectors for 1000kcmil Cu to 1750kcmil Cu)			[redacted]	• oil packed tapes
	• 115kV HPFF 3 phase repair joint w/ split sleeves for 6” & 8” pipe • 1/C-1750kcmil Cu, 0.375” paper to various conductor sizes	• —	• 2	[redacted]	• To be ordered
• Terminations	• 115kV HPFF Outdoor Termination - Ohio Brass Design • 1/C-1250kcmil Cu, 0.435” paper insulation (complete)	• 9201311	• 2	[redacted]	• 2 terminations
	• 115kV HPFF Outdoor Termination - G&W Design • 1/C-1250kcmil Cu, 0.435” paper insulation (complete)	• 9201136	• 2	[redacted]	• 2 terminations
	• 115kV HPFF Outdoor Termination – Ohio Brass Design • 1/C-1500kcmil Cu, 0.435” paper insulation (complete)	• 9201312	• 2	[redacted]	• 2 terminations • 1 partial – no paper rolls
	• 115kV HPFF Outdoor Termination – G&W Design • 1/C-1750Cu 0.420” paper insulation (complete)	• 9201313	• 3	[redacted]	• 3 terminations
	• 115kV HPFF Outdoor Termination • 1/C-1750Cu 0.375” paper insulation (complete)	•	• 3	[redacted]	• To be ordered
• 115kV Solid Dielectric Circuits - [redacted]					
	Description	Item Id	Qty	[redacted]	Strategic Spares
• Cable	• 1/C-750kcmil Cu, 0.850” EPR, 12-#14 Cu wires • w/ 0.005” Cu tape shield, jacketed 115kV class • Kerite – TPS design	• 9201123	• 2631’ • 325’	[redacted]	• 1 reel longest length (1407’) & 3 partial reels • 1 reel for complete replacement of 1 phase at Ash Street

	• 1/C-1000kcmil Cu, 0.800" EPR, 21-#14 Cu wires • w/ 0.005" Cu tape shield, jacketed 115kV class	• 9201118	• 3210'	[redacted]	Xfmr • 3 reels for longest length • (~1050') at Niagara #46
	• 1/C-750kcmil Al, 0.850" EPR, 20-#12 Cu wires w/ 0.005" Cu tape shield, jacketed 115kV class • Kerite – Triple PermaShield design	• 9201119	• 800'	[redacted]	• 1 reel for longest length at Temple Gas Orange #11
	• 1/C-1500kcmil Cu, 0.850" EPR, 30-#12 Cu wires • w/ 0.005" Cu tape shield, jacketed, 115kV class • Kerite – Triple PermaShield design	• 9201120	• 1365'	[redacted]	• 1 reel for longest length at State Campus #12 & #15
	• Elastimold premolded straight splice • 1/C-750kcmil Cu, 0.800" EPR, wire shield, 115kV	• 9201116	• 6	[redacted]	• 6 splices
• Splices	• Elastimold premolded straight splice • 1/C-1000kcmil Cu, 0.800" EPR, wire shield, 115kV	• 9201130	• 6	[redacted]	• 6 splices
	• Elastimold premolded straight splice • 1/C-1500kcmil Cu, 0.800" EPR, wire shield, 115kV	• 9201131	• 6	[redacted]	• 6 splices
	• 115kV, Solid Dielectric Outdoor Termination - G&W • 1/C-750kcmil Al, 0.800" EPR, wire shield, 115kV	• 9201141	• 0	[redacted]	• To be ordred
• Terminations	• 115kV, Solid Dielectric Outdoor Termination - G&W • 1/C-1500kcmil Cu, 0.800" EPR, wire shield, 115kV	• 9201140	• 3	[redacted]	• 3 terminations
	• 115kV, Solid Dielectric Outdoor Termination - G&W • 1/C-1000kcmil Cu, 0.800" EPR, wire shield, 115kV	• 9201142	• 1	[redacted]	• 1 termination
	• 115kV, Solid Dielectric Outdoor Termination -	• 9201138	• 2	[redacted]	• 2 terminatio

G&W ns

- 1/C-750kcmil Cu, 0.800” EPR, wire shield, 115kV

Exhibit 5

Sub-transmission – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Perform	Forestry
510	POLE - Broken	0	6				
511	POLE - Visual Rotting	0	10	251	90		
512	POLE - Leaning	0	1	16	310		
513	POLE - Replace Single Arms	2	7	19			
514	POLE - Replace Double Arms	0	0	8			
515	POLE - Repair Braces	0	6	42			
516	POLE - Replace Braces	0	2	7			
517	POLE - Replace Anchor	0	0				
518	POLE - Install Anchor	0	0	0	0		
519	POLE - Repair/Replace Guy Wire	1	6	52			
521	POLE - Tighten Guy Wire		0	73			
522	POLE - Replace/Install Guy Shield					225	
524	POLE - Guy Not Bonded				340		
525	POLE - Lightning Damage	0	1	1	1		
526	POLE - Woodpecker Damage		10	193	96		
527	POLE - Insects		0	48	23		
528	POLE - Aerial Number Missing				30		
531	TOWER - Tower Legs Broken	0	1				
532	TOWER - Numbers Missing					0	
534	TOWER - Loose Bolts/Hard	0	0	1			
535	TOWER - Repair Anti-Climb				0		
536	TOWER - Vegetation on Tower						2
537	TOWER - Structure Damage	0	2	0			
538	TOWER - Straighten Tower	0	0	0	0		
539	TOWER - Arms Damaged	0	0	0	0		
541	CONDUCTOR - Conductor	4	0	8			
542	CONDUCTOR - Static	12	2	22			
543	CONDUCTOR - Ground Wire		2	35	0		
544	CONDUCTOR - Sleeve/Conn	0	1	4			
546	CONDUCTORS - Under 25 ft				1		
547	Infrared Problem Identified	1	0				
551	LINE HDW - Insulators/Dam		3	165	19		
552	LINE HDW - Insulator Plumb				38		
553	LINE HDW - Hardware Dam	0	0	10	4		
555	LINE HDW - Lightning Arrestor		1				
563	FOUNDATION - Erosion	0	0	1	0		
571	RIGHT OF WAY - Erosion				3		
572	RIGHT OF WAY - Encroachments				74		
573	RIGHT OF WAY - Debris				19		
574	RIGHT OF WAY - Danger Tree						13
575	RIGHT OF WAY - Gate Broke				1		
576	RIGHT OF WAY - Oil/Gas Leak				0		

Exhibit 5. (continued)

Sub-transmission – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Perform	Forestry
581	MISC - Stencil Structure					944	
582	MISC - Switch Damaged	0	0	0	0		
583	MISC - Damaged Switch Ground		0				
584	MISC - Install Warning Sign				602	7	
585	MISC - Replace Signs				0		
586	MISC - Remove Steps				1		
587	MISC - Add Dirt and Tamp			0	0		
760	GIS map doesn't match field				437		
761	GIS Equipment stenciling in error on GIS				48		
762	GIS Equipment/hardware missing in GIS				62		
763	GIS Equip removed in fld, remv from GIS				46		
769	GIS Other GPS/GIS errors				1245		
901	Osmose - Identified priority pole		1				
902	Osmose - Identified reject pole			29			
903	Osmose - Insp excessive check (not rej)				6		
904	Osmose - Climbing Insp re'q (not rej)				2		
	Totals	**20**	**62**	**985**	**3498**	**1176**	**15**

Notes:

1. If the code is "Level 4" only, this implies the data is for information only and we would not send crews out to correct, but may include in a future program.

Findings are based on the inspections.

Exhibit 6.

Distribution Overhead – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Performed	Forestry
98	Street Light Hazard Condition	0	46				
99	Street Light - Not Bonded		1442				
100	Street Light - Not Bonded to Standards				6808		
101	Pole - Osmose Priority				23		
102	Pole - Osmose Reject				75		
103	Pole - Down Ground & Rod Present				55263		
106	Pole - Double Wood - NG transfer req'd			741			
107	Pole - Double Wood - Tel transfer req'd				2329		
108	Pole - Double Wood - CATV transfer req'd				987		
110	Pole - Broken / Severely damaged	5	102		4		
111	Pole - Visual rotting ground line	3	432	846	218		
113	Pole - Cu Nap Treated Birth Mark Yr			34			
114	Pole-Woodpecker Holes		73	81	436		
115	Pole - Riser guard required	0	8	80			
116	Pole - Visual rotting pole top	3	302	2288	995		
117	Pole - Leaning pole	0	82	1250			
118	Pole - Stencil / Correction Reqd					12694	
119	Pole - Birds nest (Osprey)				11		
120	Crossarm - Damage arm	4	71	415			
121	Crossarm - Loose/defective pins	9	205	998			
122	Crossarm - Wooden pins 13.2 kv		0	313			
123	Crossarm - Loose brace, hardware	2	66	358			
124	Crossarm - Damage double crossarm	0	51	271			
125	Crossarm - Damage alley arm	0	1	3			
126	Crossarm - Wood Brace Required/BIL				19526		
127	Primary on Crossarm	60	100				
130	Insulator - Broken/Cracked/Flashed	3	48	194			
131	Insulator - Floating	13	141	14			
132	Insulator-I-7 aluminum caps			2553	2817		
133	Insulator - non standard for voltage			22			
134	Insulator - AL cap assoc with switch/fus			705	392		
135	Insulator - Covered Wire on Porcelain				4326		
139	Insulator - Other (use comments)				1		
140	Primary - Insuff. grnd clearance		20				
141	Primary - Dmgd. cond/brkn strands	1	47	12			
142	Primary - Limbs on Primary	9					913
145	Primary - Damaged stirrups/Connector	0	21	3			
146	Primary - Improper Sag		14	71	6		
147	Primary - L.A. Missing Transition			306			
148	Primary - L.A. Missing End of Line			332	85		
149	Primary-LA Blown			131			
150	Transformer - Oil weeping	2	74				

Exhibit 6.(continued)

Distribution Overhead – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Performed	Forestry
151	Transformer - Bushings brkn/cracked	1	8	36			
152	Transformer - Missing ground wire		894				
153	Transformer - LA blown/missing/improper			251			
155	Transformer - Animal guards required				19836		
156	Transformer - NonStd Installation of Gap			1410			
157	Transformer - Improper/missing Bond		2896				
160	Capacitor - Oil weeping	0	0				
161	Capacitor - Bulging	0	1				
162	Capacitor - Bushings brkn/cracked	0	0	0			
163	Capacitor - Missing ground wire		4				
164	Capacitor - Blown fuse		27				
165	Capacitor - Improper/missing Bond			21			
166	Capacitor - Animal Guard Missing			432			
167	Capacitor - L.A.blown/missing/improper			38			
168	Capacitor - Control Cab Height/ground				2		
169	Capacitor - Out of Service	0	1		15		
170	Regulator - Oil weeping	0	1				
171	Regulator - Bushings brkn/cracked	0	0	1			
172	Regulator - Missing ground wire		2				
174	Regulator Control Cab. height/ground				61		
175	Regulator - Improper/missing Bond			5			
176	Regulator - Animal Guard Missing			139			
177	Regulator - L.A. blown/missing/improper			4			
180	Sectionalizer - oil weeping	0	0				
181	Sectionalizer - Bushings brkn or crack	1	0	0			
182	Sectionalizer - Missing ground wire		0				
183	Sectionalizer - Control Cab Height/Grnd				2		
184	Sectionalizer - Improper/missing bond			6			
185	Sectionalizer - Animal Guard Missing			8			
186	Sectionalizer - LA blown/miss/improper			0			
190	Recloser - Oil weeping	0	0				
191	Recloser - Bushings brkn or crack	0	0	0			
192	Recloser - Missing ground wire		0				
193	Recloser - Control Cab Height/Ground				17		
194	Recloser - Improper/missing bond			1			
195	Recloser - Animal Guard Missing			20			
196	Recloser - L.A. blown/missing/improper		0	2			
203	Switch - Gang Operated defective	0	0	0			
204	Switch - Single phase defective	0	2	0			
205	Switch - Improper/missing bond			4			
207	Switch - L.A. blown/missing/improper			40	655		
208	Switch - Handle Not Bonded		0				
210	Ground - Ground wire broken/loose	4	489				

Exhibit 6 (continued)

Distribution Overhead – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Performed	Forestry
211	Ground - Hazard condition	13	216				
212	Ground - Guard Req'd			9239			
213	Ground - non standard			1006			
214	Ground - Not Bonded to Neutral			89			
220	Guy - Guy Wire marker					12515	
221	Guy - Guy Insulator Required		1583				
222	Guy - Excessive slack in guy			1658			
223	Guy - Broken guy wire	0	597	121	1		
225	Guy - non standard bonding or insulation				24124		
226	Anchor req'd - joint owned	0	17	6			
227	Anchor req'd - sole NG	0	57	15			
231	Secondary - limb on secondary	10					1303
232	Secondary - Improper sag	1	90	210			
234	Secondary - Floating	3	14	326			
240	Service - Ins. loose from house	3	43	126			
241	Service - limb on service	7					1726
243	Service - non std or unsecured NG action	6			506		
250	ROW - Brush/Tree/Washout						398
260	GIS map doesn't match field				1782		
261	GIS Pole/line numbering in error on GIS				1149		
262	GIS Equipment/hardware missing in GIS				660		
263	GIS Equip removed in fld, remv from GIS				1197		
269	GIS Other GPS/GIS errors				1120		
270	Spacer Cable - Damaged/Missing spacer	0	24	72			
271	Spacer Cable - Bracket Damage	0	1	13			
272	Spacer Cable - Bracket not bonded			252			
273	Spacer Cable - Messenger not bonded			65			
274	Spacer Cable - Messenger Guard Missing			3			
276	Spacer Cable - Uncovered Splice			12			
280	Cutout - Defective cutout	16	97				
281	Cutout - Potted Porcelain			7126			
282	Cutout - Banded Porcelain				1808		
283	Cutout - Enclosed				3469		
284	Cutout - Non Porcelain				10861		
285	Cutout-Potted Hybrid				465		
286	Spur Tap - Not Fused				1126		
289	Cutout - Other - Use Comments				371		
290	Riser - Improper cable support/terminate	0	9	63			
291	Riser - Improper/missing bond		806				
292	Riser - Animal Guard Missing			553			
293	Riser - L.A. blown/missing/improper		2	112			
400	Infrared- Problem-Switch		1	0			
401	Infrared- Problem-Cutout	0	10	9			

Exhibit 6 (continued)

Distribution Overhead – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Performed	Forestry
402	Infrared-Problem- Splice	0	2	4			
403	Infrared-Problem- Other	0	8	14			
600	Handholes - Broken/damaged/unsecured	1	3				
602	Handholes - Missing nomenclature					9	
603	Handholes - Secondary needs repair	0				0	
604	Handholes - Other (use comments)				13		
651	Switchgear - Barrier broken/damaged/unse	0	0	1	0		
652	Switchgear - Base broken/damaged	1	3	4	0		
654	Switchgear - Cable Not Bonded		0				
656	Switchgear - Door Broken/Damaged	0	1	0			
657	Switchgear - excessive vegetation						19
659	Switchgear - Missing ground		0				
660	Switchgear - Missing Nomenclature					226	
661	Switchgear - Other				28		
662	Switchgear - Rusted/Paint peeling				31		
673	PM Transf - Door Broken/damaged/unsecu	3	76	46		1967	
675	PM Transf - Elbows/Terminator tracking/burned	0	0	1			
676	PM Transf - Excessive Vegetation						701
680	PM Transf - Missing Ground	0	6				
681	PM Transf - Missing Nomenclature				0	4853	
682	PM Transf - Mud/Debris				198		
684	PM Transf - Oil Weeping	4	40				
685	PM Transf - Pad broken/damaged	2	14	24	4		
686	PM Transf - Protection (ballards) dama				11		
687	PM Transf - Rusted/ Paint peeling				503		
688	PM Transf - Pad Pushed off Base	5	112				
740	Enclosures - Base Broken/Cracked	0	1	4	0		
741	Enclosures - Door Broken/damaged/unsec		7	3		159	
742	Enclosures - Elbows Tracking/Burned		1	0			
743	Enclosures - Excessive Vegetation						49
745	Enclosures - Missing Nomenclature					300	
746	Enclosures - Rusted/Paint Peeling				81		
801	Osmose - Identified Priority Pole		4				
802	Osmose - Identified Reject Pole		1	36			
803	Osmose - Excessive Chkg (NR) offrd				4		
804	Osmose - Climbing Insp Req'd(not reject)				7		
	Total	**195**	**11517**	**35652**	**164409**	**32723**	**5109**

Notes:

1. If the code is "Level 4" only, this implies the data is for information only and we would not send crews out to correct, but may include in a future program.
2. Findings are based on the inspections of 188,091 wood poles, 9,142 padmounted equipments, and 465 switchgears.

Exhibit 7

Underground – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Perform	Forestry
260	GIS map doesn't match field				87		
261	GIS Pole/line numbering in error on GIS				39		
262	GIS Equipment/hardware missing in GIS				3		
263	GIS Equip removed in fld, remv from GIS				35		
269	GIS Other GPS/GIS errors				623		
600	Handholes - Broken/damaged/unsecured	8	132		3		
602	Handholes - Missing nomenclature					810	
603	Handholes - Secondary needs repair	0				0	
604	Handholes - Other (use comments)				1047		
610	Manhole - Ground Rods Missing		484			1	
611	Manholes - Cable/Joint leaking		8			1	
612	Manholes - Cables bonded/Grid defective		57			5	
614	Manholes - Cracked/broken		1	6	28		
615	Manholes - Fire proofing			17		11	
616	Manholes - Improper grade				41		
617	Manholes - Missing nomenclature					791	
620	Manholes - Rerack		108			4	
621	Manholes - Ring/cover repair/replace	0	2	48	0	5	
622	Manholes - Roof Condition - Use Comments	0			30		
623	Manholes - Chimney Condition - Comments	0			7		
624	Manholes - Manhole Needs Cleaning				113		
625	Manhole - Secondary Needs Repair	6				6	
626	Manholes - No Holes in Manhole Cover	0			17		
630	Network Protector - Barriers broken/dama		0				
632	Network Protector - Oil leak	0					
633	Network Protector - Worn/damaged gasket		0				
635	Network transformer - Bushing Broken/Cra		1				
637	Network transformer - Low oil		0				
638	Network transformer - Missing Ground	0					
639	Network transformer - Missing nomenclatu					2	
642	Network transformer - Oil Weeping	0	1				
643	Network transformer - Rusted/ Paint peel				5		
651	Switchgear - Barrier broken/damaged/unse	0	0	0			
652	Switchgear - Base broken/damaged	0	0	0			
654	Switchgear - Cable Not Bonded		0				
656	Switchgear - Door Broken/Damaged	0	0	0			
657	Switchgear - excessive vegetation						0
659	Switchgear - Missing ground		0				
660	Switchgear - Missing Nomenclature					1	
661	Switchgear - Other				0		
662	Switchgear - Rusted/Paint peeling				0		

Exhibit 7 (continued)

Underground – Actual Items found December 1, 2008 to August 10, 2009

code	Description	Level 1	Level 2	Level 3	Level 4	Perform	Forestry
672	Transformer - Bushing Broken/Cracked	0	0	0			
673	Transformer - Door Broken/damaged/unsecu	0	0	0		5	
675	Transformer - Elbows/Terminator tracking/burned	0	0	0			
676	Transformer - Excessive Vegetation						22
680	Transformer - Missing Ground	0					
681	Transformer - Missing nomenclature				0	18	
682	Transformer - mud/debris				7		
684	Transformer - Oil Weeping	0	0				
685	Transformer - Pad broken/damaged	0	0	0	0		
686	Transformer - Protection (ballards) dama				0		
687	Transformer - Rusted/ Paint peeling				1		
690	Trench - Exposed Cable	0					
692	Trench Path - Sunken				0		
700	Vaults - Cable missing bond		2				
702	Vaults - Cracked/broken	0	1	0	2	0	
703	Vaults - Damaged/broken cover	0	2		2		
704	Vaults - Damaged/broken door	0	3		6		
705	Vaults - Damaged/broken ladder	0	0		0		
706	Vaults - Improper grade	0	0	0	0	0	
707	Vaults - Improper nomenclature				2	2	
708	Vaults - Light not working				7		
712	Vaults - Sump pump broken				15		
713	Vault - Secondary Needs Repair	0					
720	Submersible equip. - Excess corrosion	0	0	0	0		
721	Submersible equip. - Physical damage	0	0	0	0		
722	Submersible equip. - Leaking	0	0				
730	Anodes - Missing			15			
731	Anodes - Need replacement			2			
	Unknown	0	0	0	0	2	1
	Total	**14**	**802**	**88**	**2120**	**1664**	**23**

Notes:

1. If the code is “Level 4” only, this implies the data is for information only and we would not send crews out to correct, but may include in a future program.
2. Findings are based on the inspections of 6,982 handholes, 1,095 manholes and 72 vaults.