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May 27, 2010

VIA ELECTRONIC MAIL

Honorable Jaclyn Brilling, Secretary
New York State Department of Public Service
3 Empire State Plaza
Albany, New York 12223

Re: Case 08-E-0827, Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid's Electric Business; Implementation Plan Update 1 Report

Dear Secretary Brilling:

In accordance with the Commission's December 18, 2009 Order in Case 08-E-0827, attached please find the Implementation Plan Update 1 report of Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or "the Company") in this proceeding. This fist update report describes progress since the January 29, 2010 submission of the Company's Implementation Plan on the implementation of recommendations in the December 3, 2009, Comprehensive Management Audit report. The Update 1 report is provided in "marked-to-show-changes" format so as to facilitate review and identification of changes and updates from the January 29 Implementation Plan. A copy of this report is also being provided directly to Kate Tallmadge of Department of Public Service Staff.

Thank you for your attention to this matter.

Very truly yours,

Carlos A. Gavilondo

CAG:
Enclosure

cc: Kate Tallmadge (with Enclosure)

NS

Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid Electric Business

IMPLEMENTATION PLAN

UPDATE 1

PREPARED FOR:

THE STATE OF NEW YORK PUBLIC SERVICE COMMISSION

THREE EMPIRE STATE PLAZA

ALBANY, NY 12223

~~JANUARY 29~~MAY 27, 2010

nationalgrid

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IMPLEMENTATION PLAN UPDATE 1

INTRODUCTION

A. Discussion

Niagara Mohawk Power Corporation d/b/a National Grid (the "Company") appreciates the collegial and collaborative process in which the New York Public Service Commission (the "Commission") and its Staff worked with NorthStar Consulting Group ("NorthStar") and the Company in conducting the audit and preparing the audit recommendations. The Company's Implementation Plan for the audit recommendations is set forth below. As a general matter, the Company has found the recommendations to be quite helpful in focusing management on various issues affecting the Company.

The Implementation Plan reflects an effort by the Company to consider the recommendations from the audit, as well as an executive-level commitment to implementing the comprehensive changes outlined herein. In developing this Implementation Plan, the Company consulted with Staff on its form and content; however, given the end of year and holiday period timing as well as other scheduling challenges, the Company and Staff were able meet face-to-face once prior to production of the Plan. However, we deem the Plan to be a living document, we intend to consult with Staff very soon and submit revisions to the Implementation Plan as appropriate. In its Order directing submission of this Plan, the Commission lists several areas of "specific emphasis" in the audit, which were the subject of focused collaboration among the Company, NorthStar and Staff.[1] These areas, identified as "Opportunities" are included in the following section.

B. Opportunities

- <u>Opportunity No. 1</u> – Niagara Mohawk has yet to assess and plan adequately for its future (post 2011) role in meeting customers' long-term energy supply needs, nor has the Company integrated supply planning into its business planning process.

\- Current Status: Niagara Mohawk has made significant progress towards developing a comprehensive, long-term supply procurement policy and plan.

As the audit report recognized, the Company has made significant progress with respect to these recommendations and the Implementation Plan provides a specific strategy to continue this work. The Company proposes to establish a comprehensive framework of performance metrics for the supply procurement and risk management functions. These metrics have been instituted as group and individual goals for fiscal year 2009-10. In addition, the Company has commenced a consultant review of current procurement strategies

[1] Case 08-E-0827, *Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid's Electric Business*, Order Directing the Submission of an Implementation Plan, ("Order"), (issued December 18, 2009), at p. 5.

in order to develop a comprehensive, long-term supply procurement policy. The Company is in active conversations with Staff regarding hedging and commodity strategies, and these will be an integral part of its next rate proposal. The Company is implementing the recommendation to integrate supply procurement and energy portfolio management into the business planning process and it has been included in the scope of its 2010 plan. Finally, the Company restructured its Risk Management Policies in 2009 with increased focus on its annual supply plans, and continues to review these policies in light of the potential for the Company to have an expanded role in long-term supply procurement.

- Opportunity No.2 - While National Grid's US management has long recognized that inaccurate cost estimating in both electric transmission and distribution operations is a problem, it has only recently begun addressing it.

- Current Status: National Grid plans to correct the deficiencies in estimating through organizational improvements and processes, and providing the Estimating Center of Excellence (ECOE) appropriate tools

The Company agrees with the importance of Opportunity No. 2 and is moving forward by establishing an Estimating Center of Excellence ("Center") to improve its cost estimating processes and procedures. In addition to improving and standardizing the Company's cost estimating performance, the Center will also institute Key Performance Indicators (KPIs) in connection with project estimating. These activities, together with ongoing organizational improvements and processes at the Company, are expected in improved cost estimating for electric transmission and distribution operations.

- Opportunity No.3 – Niagara Mohawk's electric T&D operations do not have effective means to manage and control levels of service and costs for services provided by shared and other support services (e.g., information technology, legal and human resources) and organizations.

  Current Status: National Grid has almost completed implementation of Service Level Agreements (SLAs) for information systems and has commenced a program to develop SLAs for shared services functions.

To date, the Company has made significant progress in development of SLA models. Recognizing SLAs represent best practice in terms of providing performance transparency for service recipients, National Grid has elected to take a broader, more holistic view of the audit recommendations in this area. It is expanding it to incorporate the gas business and other businesses, in addition to the electric business. A great deal of work has already been accomplished to date in the development of these SLAs. Given the importance and scope of SLAs, the Company proposes to supplement the Implementation Plan as appropriate following its consultation with Staff.

- Opportunity No 4 - Niagara Mohawk does not have an effective means to determine the actual productivity of its in house or contractor resources.

- Current Status: National Grid has identified improvements required to manage its field forces more effectively and has made significant progress in implementing these improvements.

As set forth in the Implementation Plan section on Work Management, Recommendation X-1, Niagara Mohawk has already begun taking advantage of this Opportunity. On July 29, 2009, the Company and IBEW Local Union 97 entered into a Memorandum of Agreement which established a pilot program to form an internal construction group for Distribution Line Construction (DLC) projects. The Agreement outlines the DLC group implementation and measures of success over the duration of the pilot. The DLC group is constructing larger distribution projects and program work, consistent with the style of work done by the contracted work force. It is also measuring success using the same Key Performance Indicators (KPIs) as used by the contracted work force In addition the Transmission construction model includes contracted Regional Delivery Ventures (RDVs), which will be benchmarked against internal transmission work forces, specifically the Transmission Line Services and Substation Construction Services groups. All of these measures are providing the Company with methods of tracking in house and contractor work force productivity.

In addition to the four areas of special emphasis discussed above, the Implementation Plan, includes specific responses to all of the audit recommendations. The structure of the Implementation Plan follows the same order and layout as presented in the Audit Report: Corporate Mission, Objectives, Goals and Planning; Performance and Results Measurement; Load Forecasting; Supply Procurement; Program and Project Planning and Measurement; Capital and Operating and Maintenance Budgeting; System Planning; and Work Management.

This Implementation Plan, like the Company's December Responses to the Audit Report, is submitted in the spirit of collaboration and continuous improvement that has characterized this process. It should not be construed as either an acceptance of, or agreement with, any of the findings, conclusions or underlying facts set out in the Audit Report. Nor should acceptance or implementation of any of the recommendations made in the Audit Report be regarded as an admission by National Grid or any of its affiliates that their past practices were in any way deficient or as a waiver by National Grid or any of its affiliates of any legal rights or claims in any future regulatory or legal proceeding. To the extent any finding, conclusion or underlying facts set out in the Audit Report are raised in any future proceeding, the Company reserves all of its rights with respect to such findings, conclusions or underlying facts, including the right to present its position and supplement or modify the initial comments set forth herein with respect to such finding or conclusion at that time.

C. Introduction to Update 1

This is the Company's first update of its Implementation Plan. The updates provided below are generally in the form of progress and schedule updates. However, as noted in the initial Implementation Plan submittal, the Company views the Implementation Plan as a living document, subject to change and improvement where new conditions or information indicate such change would be appropriate. In cases where this update identifies changes from the initial Implementation Plan on matters other than schedule or implementation progress, this report identifies those changes in the corresponding sections below.

IMPLEMENTATION PLAN

A. Corporate Mission, Objectives, Goals and Planning

Recommendation III-1

Revise the corporate vision and objectives statements to more explicitly articulate the company's obligation to provide low cost, reliable and safe electric service to its customers. The revised statement should reflect the need to mitigate volatility and produce lower costs relative to some benchmark and could include a reflection of the total bill rather than the unit price.

Implementation Plan Leads

Executive Sponsor	Tom King, Executive Director, ED&G
Team Lead	Kristin Desousa, Executive Advisor

Background Information

In the auditor's opinion, the corporate vision statement did not express the Company's desire to provide low cost service to customers through supply procurement and delivery of electricity. The auditors stated that a clear linkage to low cost or low bills for customers would provide the appropriate linkage of vision to the supply procurement, customers and markets and operations function. This would keep ratepayer effects at the forefront of company decision-making.

Proposal to Implement Recommendation

National Grid will incorporate the recommendation in a vision statement for Niagara Mohawk Power Corporation.~~Electric Distribution and Generation (ED&G) Line of Business (LoB) mission statement. The ED&G mission statement will encompass the Corporate Vision statement, ED&G LoB priorities and expanding statements which focus on low cost and cost volatility mitigation through energy efficiency promotion.~~

The ~~ED&G LoB has crafted the~~ following vision~~mission~~ statement ~~which~~ meets the requirements previously described:

> We will be the foremost electric company, delivering unparalleled safety, reliability and efficiency, mitigating total energy costs and minimizing energy cost volatility, all of which are vital to the well-being of our customers and communities. We are committed to being an innovative leader in energy

efficiency and management.~~, and to mitigate total energy costs in the most reasonable manner, through minimizing energy cost volatility and achieving delivery performance efficiency.~~

Update 1 Changes

In order to provide more specific focus on Niagara Mohawk and its customers, the Company will implement this recommendation by revising the corporate vision statement at the Niagara Mohawk Power Corporation level, as opposed to modifying the line of business level mission statement as was proposed in the initial Implementation Plan submittal.

Schedule

Completed.

Summary of Cost/Benefit and Risk Analysis

Nominal incremental cost associated with implementation.

National Grid will work to protect rate payer interests by creation of the ~~ED&G LoB mission~~Niagara Mohawk vision statement which will provide priority guidance to management ~~.~~ ~~i~~Including the ~~Corporate Vision as part of the ED&G statement will assure alignment with corporate priorities while satisfying the~~ necessary need for focus on ~~ED&G LoB~~ priorities; low cost, and cost volatility mitigation.

Measures of Success

Not Applicable

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-2

Consolidate the management of US electric transmission and electric distribution into one LoB to provide greater visibility over NMPC electric transmission and distribution operations while maintaining NG's ability to achieve synergies and economies of scale.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Leads	Neil Proudman, Vice President Transmission & Distribution Services~~Project and Contract Management~~

Background Information

The auditors found that the LOB structure did not promote and protect the ratepayers' interests. In the auditors' opinion, Niagara Mohawk has bundled Transmission and Distribution tariffs regulated at state level. In addition, the LOB structure is claimed to hamper the ability of the Company to obtain synergies from workforces in the same area.

Proposal to Implement Recommendation

The Company believes that the LoB model provides an efficient model to deliver first-in-class services to Niagara Mohawk's electric customers. Management continues to evaluate processes to develop and implement best practices across the business to stream-line functions, improve efficiencies and protect rate payer interests. The company has undertaken an analysis and discussion regarding how it can better integrate management, provide better governance and ensure a cohesive process for its electric transmission and distribution operations. The asset management process is an area that requires further consideration by the Company.

NG has considered three different models to better integrate the management of its electric transmission and distribution operations:

- Process and governance change with no organization integration;
- Partially Consolidate organization; and
- Full integration.

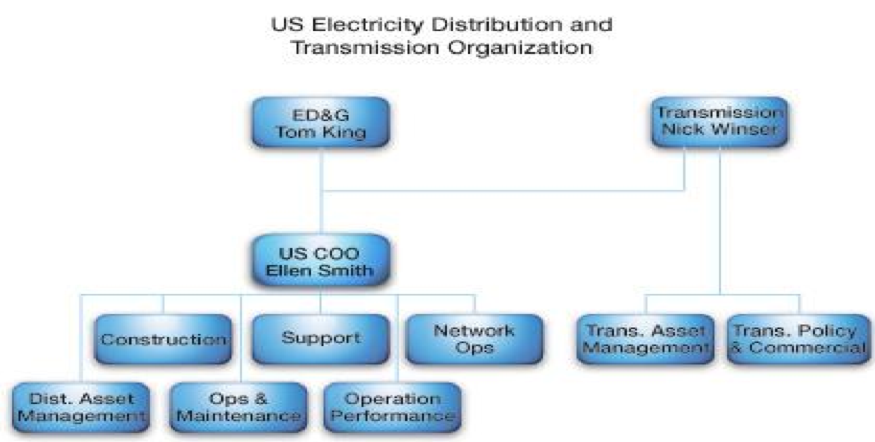
Strategic considerations included optimization of efficiencies and investment plans; maximize shared capabilities, and end-to-end responsibility for results based on a common policy, strategy and risk assessment.

After analysis of all strategic and risk considerations, the Company decided to pursue the Partial Consolidation Organizational model changes that will combine the distribution and transmission work delivery and operations. To ensure oversight at a proper level, the Chief Operating Officer will be responsible for the combined operating activities and report both to the Executive Director of ED&G and the Executive Director of Transmission.

The following will not be consolidated under the Partial Consolidation Organization model:

- Regulation, Policy and Commercial management will remain segregated to ensure compliance with regulatory visibility and control standards and preserve the distinct, but collaborative relationship between transmission and distribution. The US Policy and Strategy Committee will provide oversight and link these functions across LoBs.
- Asset Management – will remain segregated to maintain visibility and control to achieve operational objectives, preserve accountability and delivery responsibility, and assure FERC and NERC regulatory compliance. Discussions are on-going as to the future governance of this business area.

Partial Integration Organizational Model



The decision to implement the partial integration model was based on its ability to provide incremental benefits delivered through organizational changes beyond those identified for the process and governance change with no organization integration option while best reflecting the design principles (as it maintains LoB) but would require effective interface management and Service Level Agreements between Asset Management and Service Provision. Additional analysis is required and is on-going for the governance of the asset management function.

Update 1 Changes

Updated team lead information is reflected above. Schedule and progress updates, as well as changes to indicate the correct organizational name designation, appear below.

Schedule

Major Activities and Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Case for Change: Determine if a compelling case exists to change the status quo.	05/09	06/09	06/09	Complete 06/2009
Gap Analysis: Examine whether NG's US Transmission & Electric Distribution businesses are best positioned to deliver.	06/09	07/09	07/09	Complete 07/2009
High Level Design: Using a cross functional working team identify whether alternative organizational designs exist that would address objectives.	07/09	09/09	09/09	Complete 09/2009
Detailed Design	09/09	12/09	12/09	Complete 12/2009
Implementation	01/10	03/10	03/10	Complete. Staffing of the integrated U.S. Electricity Operations (Transmission and Distribution) organization has been completed.

Summary of Cost/Benefit and Risk Analysis

Nominal incremental cost associated with implementation. Benefits from the establishment of ~~a Partial Integration of National Grid's~~ US Electricity Operations~~Transmission and Electric Distribution operations~~ include:

- Maintain visibility and control over assets while preserving a clear line of delivery responsibility;
- Leveraging combined scale and shared capabilities to increase efficiency, reduce delivery cost and increase performance;
- Future convergence of contracting strategies;
- Coordinated engagement stakeholder strategy;
- Identify and draw on talent management opportunities; and

- Complies with FERC and NERC regulations.

Primary risks related to a Partial Integration organizational model include change and need for discipline to cooperate effectively across LoBs. Additional risks include duplication of efforts and diminishing Capital or Operating expenditure delivery visibility and/or control.

Measures of Success

Continue to protect rate payer interests and provide first-in-class services to Niagara Mohawk's electric customers. Promotion and protection of ratepayers' interests through Transmission and Electric Distribution operations that are cohesive and collaborative, optimizes efficiencies and investment plans, maximizes shared capabilities, and demands end-to-end responsibility for results based on a common policy, strategy and risk assessment.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-3

Prepare a business plan document for NMPC electric operations that combines strategic and operating activities with capital and O&M budgets, and ensures that the resulting plan documents the scope of business planning for the benefit of NMPC electric ratepayers. (Refers to Finding III-14).

Implementation Plan Leads

Executive Sponsor	Linda Ryan, ED&G Chief Financial Officer
Team Lead	Pam Viapiano, Vice President US Transmission Finance

Background Information

The audit found that because most of the rate effects on NMPC ratepayers were covered by the Merger Joint Agreement (MJA) which limited rate increases until the end of 2011, National Grid had little incentive to examine the effects of its strategies on NMPC ratepayers.
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Proposal to Implement Recommendation

National Grid plans to develop a NMPC business plan annually per the recommendation. The Transmission and Distribution Decision Support team will work to complete a five-year NMPC electric operations business plan document by March 2010.

This year, as part of the existing Line of Business planning process, there is a renewed focus on planning at Company (or legal entity level, including Niagara Mohawk). Information at the Company level was submitted for review in October 2009. Review of NMPC specific company level strategies and operating activities as well as capital and O&M budgets is currently ongoing.

Timelines for consolidating the detailed legal entity NMPC data and completing the first NMPC specific Business Plan for the period FY2010/11 though FY2014/15 have been agreed. It is expected that an initial draft of an NMPC Business Plan for the electric business will be completed in February 2010, with an expectation to finalize by the end of March 2010.

Transmission and Distribution decision support teams have been tasked with developing a process that can be duplicated efficiently each year to consolidate, summarize key messages and document the NMPC strategic objectives, near term priorities, as well as capital and O&M budgets.

The recommendation does not require additional information systems and will be enhanced by future implementation of new back office systems expected to be implemented in the coming years.

National Grid estimates that it will take approximately one full business planning cycle to implement a process that fully documents NMPC's electric operations strategic, and operating activities along with the approved 5-year capital and O&M budgets. In the interim, a process is in place to complete an initial 5-year NMPC business plan for the period FY2010/11 through FY2014/15 from the detail legal entity level data that was created as part of the Line of Business planning process in FY10.

Update 1 Changes

Schedule and progress updates appear below.

Schedule

Milestone	Expected Completion	Actual Completion
Initial submission of Business Plan information by legal entity data	Completed	Complete
Final submission of the Business Plan detail by legal entity	In Process	Complete 04/2010
Initial draft of the first NMPC Electric 5-year business plan document completed and approved for FY2010/11 though FY2014/15	March 2010	Complete 04/2010
Ongoing process for development, review, and completion of the NMPC 5-year business plan agreed with North Star and PSC Staff	July 2010	Complete 05/2010
Kick-off of the NMPC 5-year annual business plan A full business plan cycle will include development and documentation of: a.) NMPC strategic plan b.) NMPC priorities (near and long term) c.) 5 year financial forecast including: 1.) Profit and loss statements 2.) Capital Investment Plans 3.) Operating and Maintenance expense forecasts 4.) Revenues forecasts	On or around August of each year	Complete will be Ongoing
Completion of the annual NMPC business plan	Annually on or around March 31st of each year.	Complete will be Ongoing

Summary of Cost/Benefit and Risk Analysis

The operational distribution, transmission, and shared services costs associated with this recommendation have not yet been identified. Upon completion of the study, such costs will be incorporated into department budgets.

Measures of Success

Documented annual business plan for the total NMPC Electric Business.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-4

Integrate supply procurement and energy portfolio management into the business planning processes. (Refers to Finding III-16)

Implementation Plan Leads

Executive Sponsor	Alison Wood, Global Director of Business Development, Strategy and Planning
Team Lead	James Cross, VP of Electric Supply and Strategic Analysis Linda Ryan, ED&G Chief Financial Officer

Background Information

The Energy Portfolio Management group (EPM) is responsible for approximately $900 million of electric supply procurement for Niagara Mohawk. The auditors found that the lack of attention to these issues in the business plan was significant given the overall size and importance of these functions.

Proposal to Implement Recommendation

The company agrees with Finding III-17 of the Audit which describes its Energy Portfolio Management (EPM) procurement process as informed and effective.

The EPM group supports both the electric and gas groups. The decision was made for the EPM to develop its own five year Strategic Plan to enhance the supply procurement process. The strategic plan will better track its objectives, achievements and financial performance related to supply planning and commodity procurement functions.

The EPM Strategic Plan is aligned with corporate objectives and outlines EPM annual priorities as they support the objectives. The plan incorporates EPM strategic drivers and issues, risks and opportunities and an action plan section (which will be provided to the appropriate LoBs to include in the respective business plan). As part of the strategic plan, the EPM group will drive specific initiatives such as a long-term commodity procurement plan to protect and promote ratepayer benefits.

The EPM Strategic Plan will integrate strategy related to NYISO market and rule changes, procurement information and portfolio effects and strategy into the LoB planning process. The EPM group will provide a summary page to the LoBs which will indicate quantified strategic items for inclusion in budgets and forecasts.

Update 1 Changes

Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Develop EPM Strategic Plan	07/09	10/09	10/09	Completed 10/2009
Communicate Plan to ED&G Group for inclusion in Business Plan	10/09	12/09	12/09	Completed 12/2009
Included in ED&G Business Plan	10/09	3/2010	3/2010	~~In Process~~Complete 03/2010

Summary of Cost/Benefit and Risk Analysis

Nominal incremental cost associated with implementation.

A Strategic EPM Plan will align the procurement operations with corporate and ED&G initiatives and will keep the ED&G business informed on NYISO issues and market changes. The EPM strategic action plan will enhance the ED&G planning process and generate consideration of procurement and market issues in the development of the overall business plan.

As with any business plan, there is a risk that actual expenses will differ from what is forecasted.

Measures of Success

EPM strategic plan is successfully integrated into the ED&G business planning process.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-5

Specify how the company is going to monitor and measure the benefits to ratepayers arising from the investment in Smart Grid technology for the pilot projects. When applying for authorization for further Smart Grid technology, include a cost benefit analysis demonstrating how the results of the project will provide a net benefit to all ratepayers (Refers to Finding III-20).

Implementation Plan Leads

Executive Sponsor	Tom King, Executive Director, ED&G
Team Lead	Keith Gossage, Director Customer and Markets

Background Information

The proposed Smart Program will empower participants to reduce their energy consumption by first allowing them to understand their energy usage at a level of detail, timeliness, and ease than was previously possible, and by providing new tools and services that will help them better manage energy usage.

In case 09-E-0310, In the Matter of the American Recovery and Reinvestment Act of 2009- Utility Filings for New York Economic Stimulus, the New York Public Service Commission (NY PSC) acknowledges that, "…there are substantial benefits to be gained by beginning to invest in the use of advanced technology and communication to improve grid operations. Many of these benefits are difficult to quantify, particularly for the small-scale deployments…"

The Smart Program is designed to demonstrate that a large scale Smart Grid deployment may provide significant benefits to customer and society. It will enable more efficient energy consumption, resulting in reduced energy usage, better energy quality, improved reliability, and a general reduction in the carbon emissions (required to produce and deliver electricity to customers). The Company's expectation is that the program will reach the goals envisioned and will demonstrate in action the opportunity and value of Smart Grid.

With a Smart Grid, customers can exercise greater choices about, and control of, their energy use. At the same time, managers of the electric distribution and transmission grid will have a powerful new set of tools to improve efficiency, reliability, and security.

Referring back to case 09-E-0310, (NY PSC) asserts, "…the initial benefit may be the knowledge and experience gained. . . We agree with the DOE that the appropriate time to evaluate the net benefits of these projects is at their conclusion." In the Company's Program process, the existing performance of the network will be "base-lined" (system performance data collected) before the Program is mobilized to enable the comparison of performance data. The Program effectiveness will be evaluated before and after the Company's Smart infrastructure is deployed.

Proposal to Implement Recommendation

The NY PSC has an open docket for approval of Smart Grid pilot programs. The Company filed a proposal in the summer of 2009. On January 15, 2010, the Company filed a revision to its Smart Grid pilot program for approval by the PSC. The Company has stated in this docket how it will measure the benefits and costs for customers from the pilot.

As stated in the NY PSC Case 09-E-93190, Updated Stimulus Proposal filed by the Company, the Smart Program will measure the following:

- Demonstrate how large scale regulated investments in Smart Grid infrastructure can deliver significant benefits to customers and society.
- Customer benefit will be measured by a reduction in load and associated cost, improvement in power quality and reliability.
- Societal benefits are measured in reduction in load and associated carbon reduction.

- Demonstrate how customer energy consumption and peak demand can be consistently and significantly reduced through the implementation of technologies that provide timely energy usage information, diverse rate plans, and automation to incent and enable customers to reduce load or otherwise alter their consumption patterns.
- Establish a baseline usage for the deployment area and then use control sets of customers with differing solution sets to determine the effectiveness of each approach.

- Demonstrate how electric distribution grid operating efficiency can be improved measurably by improved monitoring and control available through a new distribution monitoring system using the smart endpoint data.
- This benefit is measured in terms of potential future reductions in line losses.

- Demonstrate how opportunities to optimize transmission network performance through enhanced distribution network information and control, and changes to customer behavior.
- This benefit is measured through reductions in critical peak loads with the combination of technology and rate mechanisms. These lower critical peaks loads reduce the overall stress on the system. Stress degrades equipment and causes reliability challenges.

- Demonstrate how distribution feeder reliability can be improved through the implementation of improved monitoring and control of the distribution grid and the integration of automated meter outage detection and restoration into a new digital distribution management systems and a new outage management system.
- This benefit is measured by reductions in customer minute interruptions.

- Demonstrate how distributed resources (both generation and storage) and electric transportation (electric and plug-in hybrid vehicles) can be safely and reliably incorporated onto the electric distribution grid through the implementation of improved monitoring, protection and capital control capabilities.
- The measurement will be the quality and usefulness of near real-time information and controls and the benefit will be a reduction in carbon-based load and an increase in availability of renewable generation.

- Demonstrate how Smart Grid technologies (including advanced meters) improve customer satisfaction by providing timely consumption and conservation options, automated lead control and alternative rate plans, and improved monitoring and control of the distribution grid.
- The measurement will be greater customer satisfaction as measured by improvement in energy savings and customer satisfaction as measured through surveys.
- The Company will also program the processes and procedures required to provide a long-term secure environment.
- The Company will feed back to the various industry working groups lessons learned to help accelerate the completion of good standards.

The Company will also work to minimize the possibility of stranded smart grid investment by making it less likely that the equipment replacement will be required once final standards are approved.

Schedule

The Schedule will be determined by commission action on the Company's filing. The pilot is proposed for two years. During those years, data will be analyzed for the purposes of answering the questions above.

Summary of Cost/Benefit and Risk Analysis

We will value each of the points as discussed above and compare to costs of the program as if it was fully implemented in the Company's service area. As in any technological or large infrastructure advancement, there are risks associated with anticipated construction and initiation costs, functionality of improvements and, there is a risk that customers will not fully leverage the technology capabilities.

Measures of Success

Customers receive greater benefit from the program than it will cost them.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-6

Recruit and appoint an independent member to NG's Board of Directors who is experienced in US utility operations and/or regulation.

Implementation Plan Sponsor and Lead

The implementation of this recommendation is the responsibility of the National Grid Board of Directors of National Grid plc.

Background Information

The auditors expressed concern that, with the retirement of the former KeySpan CEO, the Board will lack an external member who has extensive knowledge of utility operations and regulation in the United States.

Proposal to Implement Recommendation

National Grid's Board, like most boards, maintains a Nominations Committee that assists the Board in locating and vetting qualified board candidates based on a series of criteria that reflect good corporate governance. Some of the qualities that are critical for a new Board member include regulatory experience (in a utility or other highly regulated field), utility industry experience in the U.S., or the U.K., a strong ability to understand and express quantitative and financial terms, a depth of boardroom experience with large companies, experience in international markets, an engineering background, strong environmental and safety awareness, and an ability to integrate well with the culture of the current Board.

The Company's overarching need to maintain the appropriate mix of skills necessary to oversee a global organization consistent with good governance principles means it cannot ensure that the very next board member seated will have the specific criteria included in this Recommendation. However, the Company will include these criteria as highly desirable attributes and will make good faith efforts to include such a member in the future.

Accomplishments to date include communicating the audit recommendation related to the director search process to the Board of Directors as well as the Nominations Committee to ensure that US energy utility regulatory and operating experience continues to be a consideration in the search and selection of future appointments.

Schedule

This recommendation will be accomplished under the terms expressed above.

Summary of Cost/Benefit and Risk Analysis

Nominal incremental cost associated with implementation.

Specific expertise may enhance Board focus and understanding of US operations and regulatory issues and protect New York ratepayer interests. There is a risk that over-emphasizing experience with US operating and regulatory issues may cause the board to inadvertently over look a more qualified candidate who does not have direct US experience.

Measures of Success

Not Applicable.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-7

Dissolve Niagara Mohawk Holdings, Inc. (NMHI)

Implementation Plan Leads

Executive Sponsor	Colin Owyang, Senior Vice President and US General Counsel
Team Lead	Tim McAllister, Assistant General Counsel

Background Information

This is a supplemental recommendation from the Auditors. Prior to the acquisition of NMPC by National Grid (NG), Niagara Mohawk Holdings served as the holding company for NMPC and its affiliated companies. National Grid USA now serves as the holding company for NG's US holdings including NMPC. The Auditors reviewed Niagara Mohawk Holdings Board of Director (BOD) minutes for the last three years and determined that its sole function was to approve financial transactions and service contracts that could be performed by the BODs of NMPC and/or National Grid USA.

Proposal to Implement Recommendation

The Company is willing to accept this recommendation, but before it can do this, it must review the possible ramifications from the dissolution of Niagara Mohawk Holdings, Inc. Currently, the following functions are reviewing the action: Legal, Tax and Treasury. After confirmation that impediments do not exist or a rationale for continuation does not exist, the Company will eliminate NMHI.

Update 1 Changes

Tax-related issues identified during the legal review of the proposed dissolution of NMHI revealed significant associated costs with no commensurate benefit. Accordingly, the Company is updating its implementation proposal so as not to move forward with the dissolution recommendation. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimate Completion Date	Actual Completion Date	Current Status
Check with Treasury, Tax and Legal regarding ability to	February 2010	Complete 02/2010	~~In process~~Complete. Significant future potential tax implications do not favor dissolving Niagara Mohawk

eliminate separate entity			Holdings at this time. Given the minimal oversight required, customers receive no benefit from dissolution of the company
Corporate actions to merge NMHoldings into NGUSA	April 2010		Recommend this audit recommendation be eliminated.

Summary of Cost/Benefit and Risk Analysis

Risk assessment underway to assess potential costs, benefits and risks.

Measures of Success

Entity eliminated or reason for continuation stated.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-8

Consolidate the two service companies as soon as possible and as planned.

Implementation Plan Leads

Executive Sponsor	Andrew Sloey, SVP US Financial Services
Team Lead	Martin Wheatcroft, VP Controller Financial Services

Background Information

There are currently 4 service companies within the National Grid companies, three from the legacy KeySpan companies and one from the legacy National Grid companies. The three legacy KeySpan service companies are: (i) National Grid Corporate Services LLC, (ii) National Grid Engineering & Survey, Inc., and (iii) National Grid Utilities Services LLC. NG USA Service Company is the legacy National Grid service company. The Company plans to consolidate three of its four Service Companies (excluding National Grid Engineering and Survey, Inc.) once any necessary regulatory approvals are obtained and the Companies can be unified on a common financial systems platform with common allocation methodologies.

Proposal to Implement Recommendation

The implementation plan's recommendation is linked to National Grid implementing a common financial system platform as doing the consolidation without a single system is not feasible. Combining the service companies will require National Grid to move to a single allocation methodology (current allocation practices are different between legacy Keyspan and legacy National Grid service companies). This in turn will require National Grid to obtain appropriate regulatory agreement among the States for the future allocation methodology and an approval from FERC.

Update 1 Changes

The development of a common accounting system is dependent on the implementation of the planned SAP system, estimated to take 18-30 months from initiation. The initial implementation plan present the estimated completion date based on the most aggressive deployment timetable of 18 months. The revised schedule below reflects the estimated implementation timetable based on the full estimated deployment timetable of 30 months. In addition, the update includes a change to clarify the discussion of cost/benefit analysis, below. The decision to consolidate Service Companies was made at the time of the KeySpan merger. National Grid expected to incur consolidation costs as the accounting systems moved to one platform for all US companies. Thus, the costs of a single accounting system are not considered an incremental expense from the Management Audit recommendation. However, Niagara Mohawk has requested recovery of implementation costs for this accounting system in its rate case before the Public Service Commission.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Implementation of a common accounting system	Feb 2010	~~Fall 2011~~ Fall 2012		18 to 30 month process from the start in February 2010 with the earliest date for going live October 1, 2011 The date has been revised to reflect the required SAP conversion timeframe.
Determine common allocation methodology	Feb 2010	~~April 2010~~ July 2010		Allocations database that will form basis for determining common allocation methodology was completed (March 2010). Separate substream established to address due diligence requirements for proposed merger of service companies to be completed by July 2010.
Obtain regulatory approvals for single allocation methodology	April 2010	Fall 2011		Notifications to state regulators and filing of regulatory submissions to FERC expected by October 2010.

Summary of Cost/Benefit and Risk Analysis

There are no incremental costs or benefits as a result of implementing this recommendation. Moving to a single service company was outlined in the National Grid/KeySpan Merger and all incremental costs or benefits were assumed at that time.

There is a risk that post implementation of consolidation into two service companies with a single allocation methodology allocated costs change by a material amount to the National Grid operating companies, including Niagara Mohawk. The Company plans to mitigate this by thoroughly testing the selected allocation methodology prior to asking for regulatory approval.

Measures of Success

Two service companies are put in place with a single allocation methodology at the same time the company moves to a common accounting system and which results in a non-material movement in allocated costs across the National Grid operating companies.

Chapter III – Corporate Mission, Objectives, Goals and Planning

Recommendation III-9

Replace the current membership of the NMPC BOD and the NG USA BOD with members who are representative of NG's US senior management of all of its LOBs operating in New York and the US.

- Appointment of the most senior NG executives of each LOB operating in the US to the NMPC BOD would ensure that NMPC has individuals responsible for its oversight who have: the responsibility and authority to represent NMPC's shareholder (NG plc); and the knowledge of the importance of providing low-cost, reliable and safe service to NMPC's ratepayers and maintaining excellent relations with the PSC.
- Likewise, appointment of the most senior NG executive of each LOB operating in the US to the NG USA BOD would ensure that NG USA has individuals responsible for its oversight who have: the responsibility and authority to represent NG USA's shareholder (NG plc); and the knowledge of the importance of providing low-cost, reliable and safe service to ratepayers in the US and maintaining excellent relations with US regulatory agencies.
- Furthermore, the individual objectives of the NG senior executives on the BOD of NMPC could reflect NMPC's ability to provide low-cost, reliable service to ratepayers and maintain excellent relations with the PSC. Each individual's compensation (fixed and variable) could then be linked to the attainment of these objectives to the benefit of NMPC ratepayers.

Implementation Plan Leads

Executive Sponsor	Colin Owyang, Senior Vice President and US General Counsel
Team Lead	Peter Flynn, Deputy General Counsel~~Tim McAllister, Assistant General Counsel~~

Background Information

This is a supplemental recommendation. Typically, directors of the Boards of wholly-owned subsidiaries are members of senior management of the parent company whose BOD has delegated responsibility for operating and managing the subsidiary to its senior management team on behalf of the owner's shareholders.

The National Grid USA and NMPC Joint Proposal served as the basis for the approval of NG's acquisition of NMPC. Attachment 23 has two provisions that address membership of NMPC's BOD. Attachment 23 stipulates that "a majority of the RegCo board of directors will be Outside Directors (i.e., neither an officer nor director of HoldCo or any HoldCo unregulated affiliate.)" Attachment 23 defines "HoldCo as either or both of UK HoldCo and US HoldCo." HoldCo is therefore either NG USA or NG plc.

The Auditors found that NG was in compliance with Article 23 as four of the seven members (a majority) of the NMPC BOD are not officers or directors of any NG affiliate other than NMPC and therefore qualify as "outsiders" per the Attachment 23 definition. However, the Auditors argue that all four outsiders are employed by NG subsidiaries and are not senior executives of NG. The Auditors suggest that the outsiders cannot be considered 'independent" members of the BOD since they are employed by NG. Although the audit does say that having outsiders comprise a majority of directors on a wholly-owned subsidiary board has little value since the owner of the subsidiary could remove any one or all of them at its discretion. In effect, the outside directors would not be independent and they would have little influence on how the subsidiary is managed.

Proposal to Implement Recommendation

Follow appropriate corporate governance procedures and obtain requisite legal and regulatory approvals to appoint, among others, the most senior US based executives from each LOB to NMPC and NGUSA Board of Directors. Implementation of the recommendation for NMPC will require approval by the NY PSC of necessary changes in Board composition guidelines included as Attachment 23 from the National Grid/Niagara Mohawk Merger Joint Agreement approved by the NY PSC. NGUSA BOD changes have already been implemented.

Update 1 Changes

Updated team lead information is reflected above. The filing of the petition for waiver of the requirements of the Attachment 23 of the Merger Joint Proposal relative to board composition is scheduled for June. The revised schedule appears below.

Schedule

Major Activities/Milestones	Estimate Completion Date	Actual Completion Date	Current Status
Exec paper with recommendation	December 16, 2009	December 16, 2009	Completed 12/16/2009
Petition for change in Attachment 23 of MJP	~~March 2010~~ June 2010		~~In-process~~NG USA Board has been changed. NMPC expects to file petition in June for waiver of Board requirements contained in the National Grid NMPC Merger Joint Proposal contained in

			Attachment 23 of MJP.
Appoint/ Elect new Directors (45 days after approval of above)	45 days following receipt of necessary approvals		

Summary of Cost/Benefit and Risk Analysis

Nominal cost.

Measures of Success

Board composition changed.

B. Performance and Results Measurement

Recommendation IV-1

Revise the performance management process for the US Country and NMPC operating company level to include KPIs currently missing. The performance management process should include KPIs for the:

- Effect of company performance on ratepayers,
- Effectiveness of the Energy Portfolio Management Group in acquiring reliable, low cost supply or minimizing the volatility of electric prices,
- Development or implementation of comprehensive system plans,
- Effectiveness in estimating the cost of projects or performance in managing projects to completion,
- Effectiveness of centralization of US electric operations on ratepayers. (Refers to Findings IV-6 and IV-12).

Implementation Plan Leads

Executive Sponsor	~~David Pretyman, Director of Operations Performance~~Ellen Smith, Chief Operating Officer
Team Lead	David Pretyman, Director of Operations Performance~~Bill Jones, Director of Performance Management~~

Background Information

1. Revise the performance management process for the US Country and NMPC operating company level to include KPIs currently missing. The performance management process should include KPIs for the:

- Effect of company performance on ratepayers

- The Company currently tracks and manages towards several performance factors which impact customers directly, some examples include: reliability, customer service center performance, customer satisfaction and safety. The Company will consider what additional metrics are appropriate, and the corresponding KPIs for those metrics, based on the results of Recommendation III-1, where we will be addressing the customer in our line of business vision statement.

- Effectiveness of the Energy Portfolio Management Group in acquiring reliable, low cost supply or minimizing the volatility of electric prices

- The Energy Portfolio Management group is currently evaluating appropriate metrics to assess its performance in the acquisition of energy supply. Please see our response to Supply Procurement Recommendation VI-1.

- Development or implementation of comprehensive system plans

- The Company will undertake to develop an integrated system planning process (per Recommendation VII-1) and will consider whether effective performance metrics and KPIs can be established in connection with comprehensive system planning.

- Effectiveness in estimating the cost of projects or performance in managing projects to completion

- The Company is establishing an Estimating Center of Excellence to improve and standardize its cost estimating performance (see Recommendation VIII-3), and will develop appropriate performance metrics and KPIs in connection with project estimating and project actuals versus estimates.

- Effectiveness of centralization of US electric operations on ratepayers. (Refers to Findings IV-6 and IV-12).

- In addition to evaluating performance against established KPIs, the Company is establishing new KPIs corresponding to new structures and relationships flowing from the EDOT process. The Company will also determine appropriate KPIs for initiatives made possible by the centralization process (e.g., the "65-minute" initiative). These expanded performance measures will help the Company assess performance and drive towards achieving its performance ambitions.

Proposal to Implement Recommendation

This recommendation is focused on delivering the appropriate KPI and performance management framework in support of recommendations made in other chapters of the audit report. Therefore, we will work alongside the teams developing responses to the associated recommendations to address specific concerns around performance measures and KPI's.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Kick-off session to identify desired performance measures	04/05/2010	04/30/2010		Completed review and assessment of the 29 value metrics originally shared through the PSC Management Audit. Incorporated the effort to further develop the field productivity measures with the overall process oriented performance management framework articulated in the response to IV-1. We are aiming to assess the value of the individual measures against the process oriented performance framework and incorporate any T&D Integration work. This will allow us to assess the value of progressing specific measures in the context of our FY10/11 priorities, performance framework and KPI's.
Develop detailed delivery plans for each major area	05/03/2010	05/28/2010		In progress
Develop and implement recommended KPI's in alignment with Audit recommendations	06/01/2010	12/31/2010		On track

Summary of Cost/Benefit and Risk Analysis

Costs and benefits cannot be determined until work progresses within recommendations that this recommendation supports.

Measures of Success

Success will be measured using the following criteria:

- The associated recommendations are successfully implemented.
- The appropriate KPI's and performance measures are established and delivered

Chapter IV - Performance and Results Measurement

Recommendation IV-2

Utilize benchmarking in setting performance targets and establishing NG's current position against the targets.

Implementation Plan Leads

Executive Sponsor	~~David Pretyman, Director of Operations Performance~~Ellen Smith, Chief Operating Officer
Team Lead	David Pretyman, Director of Operations Performance~~Bill Jones, Director of Performance Management~~

Background Information

The Company already participates extensively in benchmarking initiatives, and will continue to do so. While benchmarking provides useful information, the Company stipulates that care must be taken to assure the benchmarking information is comparable. The Company will consider whether other uses of benchmarking information are appropriate in setting performance targets, and whether performance targets should be revisited.

In response to this Finding, the Company acknowledges that the use of benchmarking and participation in benchmarking activities does not constitute a comprehensive program. However, the Company uses benchmarking information extensively as exhibited in DRs NGMA 22 and 45. The Company uses this information to focus on specific issues and, to develop targets for first quartile performance consistent with the goal of being the foremost international electricity and gas company.

Proposal to Implement Recommendation

The Company is actively developing a comprehensive benchmarking plan, which will serve to properly convey not only the details regarding the actual benchmarking we participate in, but to also describe how the benchmarking activities are incorporated into our goal setting processes.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Develop a draft comprehensive benchmark plan	09/01/2009	12/30/2009	Complete 12/2009	Completed
Issue draft for comment and feedback	01/01/2010	02/15/2010	Complete 05/2010	~~In-progress~~Complete. Review and assessment of benchmarking participation is complete including incorporating Transmission benchmarking within the total complement. Current internal results and performance are evaluated when establishing the targets. We are actively updating our sources to incorporate the Transmission benchmark activities during the T&D Integration work in April. Transmission and Distribution benchmarking activities are aligned and coordinated through the T&D Integration activities, and the process map updated in May.
Develop final draft of comprehensive benchmark plan	02/01/2010	03/15/2010	Complete 05/2010	Complete, see above
Receive business sanction of new plan and process	03/01/2010	03/31/2010	Complete 05/2010	Complete, see above
Ensure all performance measure and target setting -processes are updated to reflect benchmarking and the plan	01/01/2010	04/01/2010	Complete 05/2010	Complete, see above

Summary of Cost/Benefit and Risk Analysis

As was previously communicated and evidenced through various data requests, National Grid participates extensively in benchmarking activities. The act of having a formalized plan that clearly identifies where the results of the benchmarking activities are readily reviewed and incorporated into the target setting processes and development of business ambitions, will serve as a stronger control and basis by which external parties can understand how benchmarking is utilized in our business.

Measures of Success

Success will be measured using the following criteria:

- A formal benchmarking comprehensive plan will be established
- Annual review of benchmarking sources and decisions on which benchmarks we will participate with.

C. Load Forecasting

Recommendation V-1

Develop energy sales forecasts and peak demand forecasts that are specific to Upstate New York and the sub-areas within NMPC service territory.

Implementation Plan Leads

Executive Sponsor	Richard Rapp, Jr., SVP Energy Portfolio Management~~James Cross, Jr., VP of Electric Supply and Strategic Analysis~~
Team Lead	James Cross, Jr., VP of Electric Supply and Strategic Analysis~~Joseph Gredder, Manager of Electric Forecasting~~

Background Information

The recommendation points to the fact that forecasts for energy and peak are only performed at the company level and that there may be value in producing forecasts at regional levels. At the corporate level forecasts for energy and peak are currently at the aggregate, or company level. Within the T&D organizations the system planners utilize localized area projections when assessing projects. Company level forecasts are not used directly, but instead used by distribution planners as a base to which spot load additions or system rearrangements are added to develop forecasted load levels for each distribution level substation transformer and circuit. Transmission planners coordinate with distribution planners when determining growth patterns within their respective transmission level planning areas.

At the system level, forecasting works annually with the NYISO on short term peak load forecasts. The information shared between the NYISO and the transmission companies in the state is used by the NYISO to generate long term peak and energy forecasts at the NYISO zonal level. National Grid's upstate territory spans six of the eleven NYISO zones in the state.

Proposal to Implement Recommendation

The Company has identified several options for implementing this recommendation. Each is discussed below.

- Option 1: "Top down" econometric forecast(s) used to inform a "bottom-up" trend analysis of peak/energy data for the sub areas.

- This option would use the aggregate company level forecast as the "umbrella" for the build-up of the subarea projections using trend analysis of the historical peak and/or energy use for each sub-area. This action would address the recommendation by providing regional peak and energy forecasts. At a zonal level, economic and electrical data currently exists and can be utilized at little expense in existing models. National Grid currently gathers weather data for the three largest zonal areas in its territory - Buffalo, Syracuse and Albany. Additional weather data may need to be gathered for the remaining zones. This generally can be obtained for several thousand dollars annually.

- Option 2: "Bottom up" combination of sub-area forecasts (ex. county level econometric) and bottom-up peak/energy (ex: substation trend analysis).

- This approach requires an assessment of existing useable electric data at the sub-transmission and lower levels and the availability of useful weather and economic data at those levels as well. Additional weather data can be obtained for several thousand dollars annually. County level economics can be obtained for approximately $5,000 annually. Incremental costs of resource costs/manpower for set-up and periodic extraction of electric system data may be required and is estimated at approximately $80,000 in man-power for set-up and then $15,000 to $20,000 annually for annual maintenance.

- Option 3: Use of regional customer load shapes for use in producing peak forecasts.

- This option would involve the use of hourly load shape information gathered by load research to project company peaks from the econometrically generated energy forecasts. The approach can produce regional forecasts, however, load shape data does not currently exist on a geographic level. New primary research including sample design, customer survey and meter installation and data collection would be required to enable this approach. In addition, the proper software would be needed to be purchased to use this data in forecasting models.
- Currently there are seven (7) electric rate classes that are sampled to produce customer load shapes for each class. The remaining classes are census metered with 100 percent of the customers having interval metering which is used to produce the customer class average load shape.
- If the sample designs are segmented geographically by three regions (requiring 21 samples), the estimated total cost to implement these designs is approximately $1.6 million, excluding the customer survey requirements. If NYISO load zones are the basis of the geographic dispersion, then 42 sample designs are required at an approximate cost of $3.9 million, excluding customer survey requirements. These estimates assume that the existing 720 sample meters in the field may continue to be used. The estimate to complete and install meters for a regional sample design project is approximately 14 months. The estimate for complete installation and planning for a zonal sample design project would be about 28 months.

  The cost of the software to utilize these load shapes in the load forecasting process is estimated at $10,000 annually.

The recommended solution is to proceed with Options 1 and 2. Option 1, the "top down econometric model" can be performed with relatively minimal cost, resources and time and provide useful information at a regional level. Research into the availability of useful distribution level information in Option 2 "bottom-up" modeling is recommended, with implementation of planning area forecasts to follow if possible.

Option 3, new primary new load research information is not recommended at this time as preliminary assessment of available information indicates that bulk level system information is available and can provide similar information to the more costly load research option.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities / Milestones	**Estimated Start Date**	**Estimated Completion Date**	**Actual Completion Date**	**Status**
Option 1: "Top-Down" Collect available information on a regional basis from existing systems.	04/01/2010	09/30/2010	Complete 01/2010	~~Initial drafts of peak and energy forecasts by NYISO zones are underway.~~ OPTION 1 has been COMPLETED A "Top-Down" regional forecast has been completed and provided to the T&D planners for use in their planning processes.
Option 1: "Top-Down" Conduct forecast modeling on a regional basis using existing techniques.	10/01/2010	03/31/2011	Complete 02/2010	~~Preliminary meeting with planning to discuss planning areas and availability of underway.~~Complete
Option 2: "Bottom-Up" Collect available information on a distribution planning level from existing systems.	01/01/2010	12/31/2010		OPTION 2 is IN PROGRESS. Meetings/calls with the T&D planners have begun. Regional mapping of Distribution and Transmission planning areas

				to NYISO zones has been completed.
Option 2: "Bottom-Up" Conduct forecast modeling on a regional basis using existing techniques. (if go)	01/01/2011	06/30/2011		

Summary of Cost/Benefit and Risk Analysis

Major Activity	Dept/Area	Estimated Cost
Option 1: "Top-Down" Collect available information on a regional basis from existing systems. Conduct forecast modeling on a regional basis using existing techniques.	Forecasting Forecasting	$0 / min labor $2,500 per year / min labor
Option 2: "Bottom-Up" Collect available information on a distribution planning level from existing systems. Conduct forecast modeling on a regional basis using existing techniques.	System Planning Forecasting	$80,000 1st year / $15-20,000 ongoing $10-20K yr1 / $10K ongoing / min labor
NOT RECOMMENDED Option 3: Load Research Metering	Load Research	Up to $4,000,000

The proposed approach will meet staff's recommendation and provide useful information to the system planning, DG, forecasting and other groups within the company for use in system planning and load forecasting.

Measures of Success

Success will be determined as these improved models and projections are used by system planning in their work.

Chapter V– Load Forecasting

Recommendation V-2

Implement end-use data collection activities to support implementation of the SMART GRID program, enhance the development of Energy Efficiency (EE) programs and initiate efforts toward end-use modeling.

Implementation Plan Leads

Executive Sponsor	James Cross, Jr., VP of Electric Supply and Strategic Analysis
Team Lead	Joseph Gredder, Manager, Electric Forecasting

Background Information

This recommendation requires the company to implement end-use data collection activities in order to support three activities. The activities are as follows: a) the electric forecasting process; b) the Smart Grid pilots; and c) the Energy Efficiency programs.

There are a number of initiatives currently active with respect to these activities. Each is described below.

- Forecasting: While the forecasting process does not currently include an end-use modeling method, it does include appliance saturation surveys (such as air conditioning), which are reviewed to help understand changes in customer use.

- Smart Grid: The Company is currently evaluating the impact of the recent DOE awards. It has proposed an extensive Smart Grid pilot in two of the major markets within its service territory – the Syracuse and Albany regions. Over 80,000 customers would receive Smart Grid technology. The Smart Grid pilot would be targeted to customers across all rate classes - residential, commercial and industrial - providing market segmentation. The recommendation and finding V-6 seek to ensure that proper market segmentation is made and that customer end-use data is collected. The outcome of the above-mentioned evaluation of options will affect the extent of data collection

- Energy Efficiency: The energy efficiency group currently conducts customer surveys and activities which gather end-use information within its New England territories which may or may not be transferable to New York. This information is used to enhance the development and evaluation of the EE programs.

The Company has identified several options for implementing this recommendation. Each is discussed below.

- Option 1 ("Planned" EE End-Use Metering): Collect customer end-use metered data for the primary end-uses, lighting and cooling, described above as part of the EE evaluation process currently planned[2]. The Company's efficiency programs target certain customer segments. Therefore, customer end-use metered data collected will be limited to residential customers with central air conditioning, small commercial and industrial customers and industrial customers consuming greater than two MWs. It is estimated that data collection for small business lighting would cost approximately $2,000 to $4,000 per site and may require approximately 40 sites (or $80K to $160K in total). It is estimated that data collection for residential cooling would cost approximately $5,000 per site and may require approximately 30 sites (or $150K in total).

- Option 2 (End Use Surveys): Conduct new primary end-use customer surveys. This option would involve customer surveys to determine end-use and appliance saturation information for the service territory. [This option would also be of use in understanding customer use trends in recommendation 3 below]. A typical residential (telephone) customer survey of the magnitude required by this study is on the order of $50,000 for the approximately 1,500 random surveys required. The estimated cost to (telephone) survey the commercial sector is on the order of $100,000 for approximately 600 random surveys required.

- Option 3 (Best Practices): Conduct a survey and/or review existing information on best practices among comparable utilities in the area of end-use modeling. This would be used to determine what models, if any, are widely used in the industry. Additional monies would be required for the purchase and training of any third party models selected. This could be on the order of $15,000-$20,000 annually for software and training.

- Option 4 (Smart Grid): As future Smart Grid pilots are conducted, collect customer end-use metered data and survey information. This option would involve collecting energy and peak use data from the major end-uses within the customer premises (lighting, cooling, refrigeration, etc.).

- Option 5 ("Expanded" EE End-Use Metering): This option would be to expand the planned end use data collection discussed in Option 1 above to include substantially

[2] As part of the energy efficiency programs that the Company offers and evaluates in New York end-use data will be collected. The Company began offering the Small Business Services Electric Efficiency Program and the Residential Central Air Conditioning Efficiency Program in 2009. The Small Business Services Program primarily installs energy efficient lighting. The Company is committed to completing evaluation studies which will involve end use metering of lighting equipment. These types of evaluation studies normally involve installing time of use lighting loggers on a statistically representative sample of program participants. The Residential Central Air Conditioning Efficiency Program primarily offers incentives for the installation of high efficiency central air conditioning equipment. In 2010, the Company is committed to completing evaluation studies which will involve end use metering of central air conditioning equipment. The Company expects to complete this study jointly with all New York electric utilities implementing residential air conditioning efficiency programs in New York.

all residential and small commercial end uses. The estimated costs would be approximately $18,600,000 to achieve and capture over 80% of the customer energy use. This is based on 1) $150,000 to survey customers in order to create a proper sample, 2) 1,000 residential sites at $10,000 per site for a total of $10,000,000 3) 600 commercial sites at $14,000 per site for a total of $8,400,000.

- Option 6 (Load Research Metering): Collect primary metered data collection via load research for a representative sample of customers for each targeted end use in each region or zone. This would involve conducting a customer survey as in Option #2 to estimate how many customers in the population have each targeted end use appliance. Interval data recorders would need to be installed on a representative sample of customers for each of the targeted end use classifications.

Sample design, installation, data collection and analysis would involve similar cost and timing as that described in Recommendation 1, option 3. This is estimated to be on the order of an average $112,000 per rate class for each separately sampled region or zone. For example, in order to complete an end-use study for the same number of rate classes currently metered by load research, seven, would cost close to $800,000.

Recommended Solution:

The recommended solution is to proceed with the "Planned" EE End-Use Metering (Options 1), End Use Customer Surveys (Option 2) and Best Practices (Option 3). New primary metered data collection for major end-uses in two key customer segments is already planned and should be leveraged to the greatest extent possible. Since Option 1a is limited to EE program participants, it is also recommended to proceed with option 2 to gather system-wide end-use customer survey information. [This option can also be used to address Recommendation 3 (Option 3, customer use trends)]. Option 3 is recommended to research best practices in the industry and incorporate those that are appropriate into our models and processes. It is recommended that the Smart Grid option (Option 4) be monitored and reassessed pending a go/no go decision on the pilots.

The option to do "Expanded" EE End-Use Metering (Option 5) is not recommended because the recommended options to collect lighting and residential cooling information and end-use survey data from our residential and small commercial customers captures what is necessary for the EE group to make more informed planning and evaluation decisions for the current programs that they run. As the EE programs expand, more data specific to those program will be collected and can be shared with load forecasting. These, coupled with Best Practices research will provide the forecasting group significant information to inform and improve the forecasting process. For these same reasons it is also not recommended to pursue Load Research data collection (Option 6). In addition, load research is typically targeted towards whole house/business usage and not at specific end-uses.

Update 1 Changes

Several of the activities associated with implementation of this recommendation are subject to the timing of PSC regulatory approvals. Accordingly, the implementation schedule has been revised to reflect the dependent timing. This change and other schedule and progress updates appear below.

Schedule

Major Activities / Milestones	Estimated Start Date	Estimated Completion Date	Status
Option 1: "Planned" EE End-Use Metering Implement and collect end-use small commercial lighting data per EE plan.	06/01/2010	~~03/31/2011~~ TBD	
Implement and collect end-use residential cooling data per EE plan.	05/01/2010	~~10/31/2010~~ TBD	OPTION 1 schedule is contingent on the timing of the DPS staff joint study schedule. The Residential Central Air Conditioning Efficiency Program ended on March 31, 2010. The Company will participate in a joint study to meter central air conditioning equipment from 2009 participants, but the start of the study has been delayed until later this year. The Small Business Services Program lighting end use metering will be completed jointly with all New York electric utilities and an RFP is expected to be issued 4th quarter 2010.
Incorporate information into EE program evaluation and projected future targets.	11/01/2010	~~12/31/2010~~ TBD	~~Initial review of existing data is underway.~~ Study has been delayed until later this year and is contingent on the timing of the DPS staff joint study schedule.
Incorporate EE targets into forecasts.	01/01/2011	~~06/31/2011~~ TBD	
Option 2: End-Use Customer Survey Collect end-use customer survey information	04/01/2010	12/31/2010	OPTION 2 is on hold: This initiative will be coordinated by the National Grid Energy Efficiency group pending PSC approval to proceed. The PSC has asked ~~other~~all utilities to wait until a similar study being conducted by Con Ed is completed.

Use survey data to inform / update models, if appropriate	01/01/2011	06/30/2011	
Option 3: "Best Practices" Conduct research on alternative models and methods	04/01/2010	09/30/2010	
Cost / Benefit Assessment	10/01/2010	03/31/2011	OPTION 3 is on schedule.
Software/Training (if go)	04/01/2011	09/30/2011	
Implement (if go)	10/01/2011		
Option 4: Smart Grid (pending pilot go/ no-go) Additional Smart Grid data collection specifications (if go)	06/01/2010*	~~12/31/2010~~ TBD	
Collect customer survey information	01/01/2011	~~12/31/2012~~ TBD	OPTION 4 schedule is contingent on the timing of the PSC approval of the program. The schedule provided in the implementation plan was contingent on Smart Grid approval by the PSC last year. This was not received and National Grid made an updated filing for the program in mid January. Depending on the outcome of that filing, the appropriate revisions to the schedule will be made.
Implement Smart Grid pilots and data collection (if go)	01/01/2011	~~12/31/2012~~ TBD	
Use data collected to inform / update forecasting and EE plans and models.	01/01/2013	~~12/31/2013~~ TBD	

* Start Date following PSC approval of Smart Grid pilot.

Summary of Cost/Benefit and Risk Analysis

Major Activity	Dept/Area	Estimated Cost
Option 1: "End-Use meter data" Implement and collect end-use residential lighting data per EE plan.	EE	$80,000 to $160,000
Implement and collect end-use	EE	$150,000

residential cooling data per EE plan. Incorporate information into EE program evaluation and projected future targets. Incorporate EE targets into forecasts.	 EE Forecasting	 $0 / min labor $0 / min labor
Option 2: "Customer Survey" Collect end-use customer survey information Use survey data to inform / update models, if appropriate	 Customer (Market Research) EE/ Forecasting	 $150,000 / year $0 / min labor
Option 3: "Best Practices" Conduct research on alternative models and methods Cost / Benefit Assessment Software/Training (if go) Implement (if go)	 Forecasting Forecasting Forecasting Forecasting	 $0 / min labor $0 / min labor $10-20k (yr1)/ $10k ongoing $0 / min labor
Option 4: Smart Grid (pending go / no-go) Additional Smart Grid data collection specifications Collect customer survey information Implement Smart Grid pilots and data collection Use data collected to inform / update forecasting and EE plans and models.	 EE / Forecasting Market Research Smart Grid EE / Forecasting	 $0 / min labor $150,000 per Smart Grid schedule $0 / min labor
NOT RECOMMENDED Option 5 "Expanded" EE End Use Metering Option 6 Load Research Metering	 EE Load Research	 $18,600,000 $800,000

The proposed approach will meet staff's recommendation and provide useful information to the EE, DG, forecasting and other groups within the company for use in program planning and evaluation.

Measures of Success

Success will be determined as end-use data is used to improve electric forecasting, smart grid and EE program evaluation.

Chapter V – Load Forecasting

Recommendation V-3

Coordinate load forecasting activities with the Customer Markets group to support development of EE and Distributed Generation programs and system/supply planning, and to incorporate the projected results of those programs into the load forecasting models and results.

Implementation Plan Leads

Executive Sponsor	James Cross, Jr., VP of Electric Supply and Strategic Analysis
Team Lead	Joseph Gredder, Manager, Electric Forecasting

Background Information

The findings and subsequent recommendation are intended to ensure coordination between the customer groups including energy efficiency & distributed generation, system planning, supply planning and forecasting.

Historically, the load forecast was not explicitly adjusted for EE and/or DG. The underlying concept had been that to the extent existing EE programs and DG interconnections continue to run at historical levels, the forecast model implicitly accounts for them in its regression variables. To the extent current projected energy reductions are significantly higher or lower than historical projected energy savings, then an adjustment can be made to account for these changes that the model would not have accounted for. Historically, in New York the company has not been implementing its own EE programs until recently. Thus, scenario analysis has recently been performed on the current business plan forecast (FYE 2010) and projections for the new company EE programs have been incorporated into the forecasts. With regard to the use of the forecast for development of EE programs, forecasts are provided periodically to the customer group for consideration in their plans. Use of distributed generation estimates are not currently applied in the company level forecasts due to the uncertainty of their operation at peak load conditions since they are not under the Company's control. However, they may be considered as "spot" load adjustments in the regional forecasts to be generated as part of recommendation one above. With regard to supply (procurement) planning, sales forecasts are routinely provided for use in informing procurement decisions. For system planning, discussions are underway as part of recommendation listed above.

The Company has identified a few options for implementing this recommendation. Each is discussed below.

- Option 1: Incorporate the projected energy and demand reductions from Energy Efficiency programs and Distributed Generation interconnections into the forecast models as post modeling "below the line" adjustments to the forecasts. Scenario analysis can be performed on various penetration levels of each as well as other initiatives including Smart Grid.

- Option 2: Incorporate the projected energy and demand reductions from Energy Efficiency programs and Distributed Generation interconnections into the forecast model as an adjustment to a variable(s) or alternate models. Research would be performed on alternative options. Incremental costs will be incurred should new modeling software, training and/or data collection be required.

- Option 3: Analyze customer usage trends and incorporate into the models as appropriate. a) This can be accomplished by looking at existing billing and system metered data for trends and patterns. No additional resources would be required to examine existing data. b) Determining the reasons for any trends or patterns found would need to be investigated and additional monies and resources in terms of end-use customer surveys as discussed in option 2 of recommendation two above.

The Company determined that the recommended solution is to proceed with Option 1 (post model adjustment) first. In parallel with that it is recommended that an analysis of customer usage trends from existing data be reviewed as per Option 3a and that research on alternative models and methods per Option 2 be conducted. A go/no-go decision on proceeding with Option 2 alternative models would be determined following the research and cost benefit assessment. Similarly, a go/no-go decision on proceeding with Option 3b would be determined as part of the decision process for recommendation 2, option 3 above.

This solution is selected as it is a multi-step process which provides initial useful response at low cost to the recommendation while more detailed (and possibly more costly) steps are assessed

Update 1 Changes

Schedule and progress updates appear below.

Schedule

Major Activities / Milestones	Estimated Start Date	Estimated Completion Date	Status
Option 1: "Post Model Adjustments" Collect projections from customer groups	01/01/2010	06/30/2010	~~EE estimates have been incorporated into the sales forecasts for the business plan and rate case.~~
~~Option 2: "Alternative Model / Methods"~~ ~~Conduct research on~~	07/01/2010 ~~01/01/2011~~	12/31/2010	OPTION 1 is in progress. Projections for EE have been

~~alternative models and methods~~ ~~Cost / Benefit Assessment~~ ~~Software/Training (if go)~~ Implement "below the line" adjustments to modeled forecasts to capture EE/DG projections.	~~07/01/2011~~ ~~10/01/2011~~	~~06/30/2011~~ ~~09/30/2011~~	collected and incorporated into the load forecasts (completed in conjunction with Rec'd V-1, Option 1, regional forecasts above).
Option 2: "Alternative Model / Methods" Conduct research on alternative models and methods	04/01/2010	12/31/2010	=
Cost / Benefit Assessment	01/01/2011	06/30/2011	OPTION 2 is in progress. Preliminary discussions internally on a questionnaire for contacting other utilities are beginning.
Software/Training (if go)	07/01/2011	09/30/2011	=
Implement (if go)	10/01/2011		=
Option 3: "Customer Usage Trends" Analyze customer use trends	04/01/2010	09/30/2010	=
Collect end-use customer survey information (can use the same survey as in rec'd 2, option 3 above) **	04/01/2010	12/31/2010	OPTION 3 is in progress. Preliminary tables showing historical and forecasted usage trends have been prepared.
Use survey data to inform / update models, if appropriate	01/01/2011	06/30/2011	=

Summary of Cost/Benefit and Risk Analysis

Major Activity	Dept/Area	Estimated Cost
Option 1: "Post Model Adjustments" Collect projections from customer groups Implement "below the line" adjustments to modeled forecasts to capture EE/DG projections.	EE/ DG Forecasting	$0 / min labor $0 / min labor
Option 2: "Alternative Model / Methods" Conduct research on alternative models and	Forecasting	$0 / min labor

methods Cost / Benefit Assessment Software/Training (if go) Implement (if go)	 Forecasting Forecasting Forecasting	 $0 / min labor $10-20k (yr1)/ $10k ongoing $0 / min labor
Option 3: "Customer Usage Trends" Analyze customer use trends Collect end-use customer survey information Use survey data to inform / update models, if appropriate	 Forecasting Market Research Forecasting	 $0 / min labor $150,000 $0 / min labor

The proposed approach will meet this recommendation and provide useful information to the EE, DG, forecasting and other groups within the company for use in program planning and evaluation.

Measures of Success

Success will be determined as improved models and approaches are used to improve the EE program planning and the load forecasting process.

D. Supply Procurement

Recommendation VI-1

Establish a comprehensive framework of performance metrics for the supply procurement and risk management functions. The metrics should build on NG's corporate vision and goals and need to reflect the changing electric supply procurement market and NG's preferred strategy in that market.

Implementation Plan Leads

Executive Sponsor	Richard Rapp, Jr., SVP Energy Portfolio Management
Team Lead	James Cross, Jr., VP Electric Supply and Strategic Analysis

Background Information

The Auditors suggested that NG does not have appropriate electric supply portfolio performance goals or metrics to guide its performance. However, the Company does file a quarterly report on its electric supply prices and volatility, measured by the Coefficient of Variance.

As part of the "collaborative process" during the audit, the Company provided evidence of significant progress towards developing a comprehensive, long term supply procurement policy and plan. The following represents further proposed steps.

Proposal to Implement Recommendation

The Company proposes to establish a comprehensive framework of performance metrics for the supply procurement and risk management functions. The Electric Supply group has overseen the implementation of a NY Load Bidding Report with metrics to limit the portfolio's exposure to Real Time NYISO price volatility. The metrics shall be measured on a calendar year basis and reported on a fiscal year basis, as described below.

- Metric #1: Limit the quantity of Real Time NYISO purchases to +/- 10% of the total NM Commodity Load.
- Metric #2: Limit the net cost of Real Time NYISO purchases to <3% of the total energy (LBMP only) costs.

These metrics have been instituted as group and individual goals for fiscal year 2009-2010, with accountability for the Electric Supply group with regards to their variable pay component in the Performance for Growth (P4G) system.

These metrics will be initiated by the Electric Supply front office group and will be reviewed and reported by the Risk Management middle office group, which creates an appropriate check and balance on the metric results.

In addition, from the list of "Possible Performance Metrics for Power Supply Procurement" listed in Exhibit VI-5 (p. VI-12), several of the metrics are now being reported by the Electric Supply front office to the Risk Management middle office on a monthly basis.

Also, performance metrics regarding New York utilities are being incorporated in the Energy Portfolio Management (EPM) department's Key Performance Indicators (KPIs) for fiscal year 2009-10. As noted in Finding VI-14, "NG has developed metrics for supply portfolio performance that incorporate available data on New York utilities (prices and volatility metrics from the quarterly NYPSC filings). These metrics are being incorporated into the department KPIs for FY 2009-10." Niagara Mohawk reports quarterly volatility metrics to the PSC in compliance with the NY PSC's Order in Phase II of Case 06-M-1017, and also collects this quarterly data from the other reporting New York utilities for comparison.

As noted in Finding VI-14, "NMPC has provided evidence of its significant progress towards developing a comprehensive, long term supply procurement policy and plan." Efforts are underway to implement recommendations on process improvement and further develop a comprehensive, long term supply procurement policy and plan. The Company will integrate the supply procurement planning process within the ED&G business plan process, and has developed a process for monitoring and updating the long term supply procurement strategy and short term tactical plans.

Finally, the Company has commenced a consultant review of current procurement strategies across all its utilities and an assessment of different procurement approaches, as well as the development of a systematic framework to facilitate corporate decision-making and to better formulate regulatory strategies. This review and implementation of the resulting recommendations are significant steps towards developing a comprehensive, long term supply procurement policy.

Update 1 Changes

Schedule and progress updates appear below.

Schedule

Major Activities / Milestones	Estimated Start Date	Estimated Completion Date	Actual Completion Date	Current Status
Develop performance metrics and input them into the P4G system.	April 1, 2009	Sept 1, 2009	~~Sept 1,~~ Complete 09/01/2009	~~Completed~~As scheduled, performance metrics for load bidding were developed and entered into the P4G system by September 1, 2009.
Begin monthly reporting of performance metrics starting with Jan 2010.	Jan 31, 2010	Feb 28, 2010	Complete 02/01/2010	~~On track~~ The monthly reporting and review of loa bidding performance metri began on schedule in January 2010. This implementation item is complete, and the monthly process will continue.
Incorporate supply portfolio performance metrics (prices and volatility metrics from the quarterly NYPSC filings, as well as available comparative data on other NY utilities) into KPIs for FY 2009-10.	Jan 1, 2010	Feb 28, 2010	Complete 02/01/2010	~~On track~~Complete. The supply portfolio performance metrics (price and volatility metrics from the quarterly NYPSC filings, as well as available comparative data on other NY utilities) have been incorporated into KPIs for FY 2009-10. These KPIs were presented at the fiscal year-end business review meeting on May 4th. The quarterly process of reporting these KPIs will continue.

Summary of Cost/Benefit and Risk Analysis

No incremental costs or savings would result from this recommendation. There are no identified risks associated with this proposal.

Measures of Success

Our success will be measured by the monthly results of the load bidding goals, limiting the Niagara Mohawk portfolio's exposure to Real Time NYISO price volatility, and thus fulfilling the goal of mitigating commodity volatility for customers.

Chapter VI – Supply Procurement

Recommendation VI-2a

Continue activities to develop a long-term strategy and short-term tactical supply procurement plan as laid out in the Collaborative meetings and incorporate these plans into the corporate business plan.

Background Information

NorthStar met with NG representatives and the PSC Staff to learn what efforts and changes the Company had undertaken since the conclusion of on-site audit work. During this meeting the Company provided:

- Graphs that supported the decision to contract for only 200-MW to replace the 560-MW NMP1 prior contract. The primary reasons for contracting the lower capacity was the reduction in required hedging from 81 percent to 60 percent effective in 2009.
- Briefing package to demonstrate that it had taken additional steps to develop an appropriate comprehensive supply planning strategy and portfolio.
-

The Auditor acknowledged that significant progress was made, but further work was needed. Currently, Internal Audit is reviewing the EPM and three office model. It is expected that findings from that report will result in actions to meet these recommendations.

Proposal to Implement Recommendation

The Company will be preparing its strategic response to moving from RSA hedging/mass market obligations to the post-RSA actions under Commission orders. This comprehensive planning process will incorporate scenarios for meeting NMPC customer needs post-2011, as well as operations. The rate mechanisms that the Company proposes for post-2011 are included in the rate case. The Company will continue its regular portfolio reviews with the Commission staff, and will continue to focus on reliable long-term supply within the NY ISO market framework. The Company does have 46 existing IPP contracts and the Nine Mile #2 financial hedge to provide the mass market customers a commodity hedge post-2011. The regulatory treatment will be addressed with the PSC Staff prior to finalizing a commodity hedging strategy that would include the existing hedges and a plan for procuring additional hedges to meet pricing and volatility metrics.

Update 1 Changes

Schedule and progress updates appear below.

Schedule

Major Activities / Milestones	Estimated Start Date	Estimated Completion Date	Actual Completion Date	Current Status
Commence Internal Audit of electric supply procurement.	Nov. 15, 2009	Feb. 28, 2010	Complete January 2010	~~On target~~The Internal Audit of electric supply procurement concluded on January 27, 2010, ahead of schedule.
Receive and review final report from Internal Audit.	Apr. 1, 2010	Apr. 15, 2010	Complete March 2010	~~Not started~~The audit completion resulted in the issuance of a final report from Internal Audit, which was distributed on March 16, 2010, ahead of schedule.
Develop implementation plan to address gaps identified in Internal Audit report.	Apr. 16, 2010	May 31, 2010		~~Not started~~Development of an implementation plan to address gaps identified in the Internal Audit report is underway.
Implement changes to address gaps from the Internal Audit report.	Jun. 1, 2010	Aug. 31, 2010		~~Not started~~Implementation plan is planned to be completed by August 31, 2010.

Summary of Cost/Benefit and Risk Analysis

No incremental costs or savings would result from this recommendation.

Measures of Success

Our success will be measured by the successful implementation of the plan to meet any issues identified by Internal Audit, in addition to the final Internal Audit's verification of the existing three office model as best industry practice.

Chapter VI – Supply Procurement

Recommendation VI-3

Define and restructure the risk management policies, procedures and functions to assure appropriate monitoring of risk factors as the transition and long-term supply procurement plans are implemented. The risk management tools should incorporate appropriate market monitoring to know when contingencies are needed.

Background Information

The Audit report suggests that the Company's current risk management framework will not handle procuring energy capacity and hedging instruments in future energy markets. However, Finding VI-12 positively notes that risk management policies in place for energy supply are appropriate for the short term. As described in the implementation plan to address Recommendation VI-2, the forthcoming Internal Audit report will identify any issues and refer to best practices. The current adequate risk management policies will continue to be used in the "transition period" from now through 2011, and presumably beyond if they are affirmed as best practice by Ernst and Young.

Proposal to Implement Recommendation

The Company continually reviews its Risk Management Policies, including the areas included in this Recommendation. In light of current market conditions, the view of risk is being expanded beyond financial impacts and credit-worthiness to include considerations of market structures and balance sheet impacts. The EPRMC has been restructured in April 2009 with increased control over annual supply plans, and expanded to include senior management from Regulatory, Legal, Electric Distribution and Gas Distribution. Currently EPRMC membership has seven members of which all are officers. In addition, the Commodity Management Committee was expanded in July 2009 to include representation from both gas and electric regulatory.

The Company recognizes that, particularly with the potential for an expanded role in long-term supply procurement, it must reevaluate its risk management processes related to supply procurement. This review is an ongoing process, and the Company is in regular contact with the Commission and Staff. Long term procurement activities would be developed in a collaborative manner with full cost recovery.

Finding VI-12 notes that risk management policies in place for energy supply are appropriate for the short term and will continue to be implemented through the transition through 2011 and, as deemed appropriate, beyond. It should be noted that the Company has developed a long term electric price forecast through 2017, which is updated weekly.

Opportunities will be sought to improve communication between the front and middle office regarding regulatory issues and long term supply strategic plans. The EPM group will continue to present their electric procurement strategies for Niagara Mohawk and the other utilities to the EPRMC for approval on an annual basis. Any need to enter into long term contracts will be aligned with the proper regulatory recovery mechanism, particularly for the period beyond 2011. The Company will confer with the PSC Staff on how to align its long term supply strategy with the Commission's objectives. The Company's procurement strategies have evolved with the marketplace and will continue to do so. As the Company confers with PSC Staff on the future plans for the electric supply portfolio, it will have future opportunities to demonstrate its abilities to analyze and strategize, within the appropriate regulatory recovery mechanisms.

Finding VI-12 notes that risks associated with energy supply are not listed on corporate level "risk matrices." However, EPM tracks both market and credit risks with assistance from Risk Management; and any non-systemic risk that is identified would be captured in the corporate risk matrix.

Schedule

Since the elements of the implementation plan are similar, please reference the implementation schedule for Recommendation 2a.

Summary of Cost/Benefit and Risk Analysis

No incremental costs or savings would result from this recommendation.

Measures of Success

Our success will be measured by the successful implementation of the plan to meet any issues identified by Internal Audit, in addition to the final Internal Audit's verification of the existing three office model as best industry practice.

E. System Planning

Recommendation VII-1 through VII-10

There are ten recommendations (VII-1 to VII-10) relating to system planning which are detailed below. For this chapter, the Company believes it is most appropriate to provide a unified response because our plan is to produce an integrated system plan that addresses all of the audit recommendations in this chapter.

VII-1	Develop an integrated NMPC Transmission and Distribution system-wide plan. (Refers to Findings VII -4,VII-8, VII-14, VII-15, VII-16, VII-17, VII_ 18, and VII-31)
VII-2	Utilize annual operational reports such as the Transmission System Reliability Performance Report and the Distribution Reliability Report as inputs to asset health/strategy and subsequently recommended projects. Demonstrate how the annual integrated system plans directly address reliability issues raised in the two reports. Show progress against known system deficiencies such as "worst-performing circuits" and outage causal factors. Identify and relate capital programs and projects to specific reliability performance issues and measure their effect. (Refers to Findings VII -3, VII-4, VII-5, VII-25, and VII-26)
VII-3	Evaluate the effectiveness of system plans each year to determine how well they are meeting system planning objectives such as reliability goals, and directing capital resources to specific issue areas and performance trends. (Refers to Findings VII-8,VII -11, VII-18, and VII-29)
VII-4	Evaluate the causal factors and impact on capital budgets and system planning of projects "walked in" and "walked out" of the system plans. Identify why the projects walked in were not initially planned, what will be done in future planning cycles to remediate these issues and how projects displaced into future planning periods will be accommodated. (Refers to Findings VII -11 and VII-29)
VII-5	Perform economic studies to identify more efficient system modifications that can reduce the costs of service and increase utilization of resources. (Refers to Findings VII -26 and VII-29)
VII-6	Evaluate outages that were avoidable due to improved system planning (capital) and preventive maintenance (O&M) such as vegetation and failed equipment. Determine the budget necessary to provide the level of maintenance that would have prevented the outages and compare against the current maintenance budget. Analyze the costs associated with the outages with incremental increases in maintenance programs. (Refers to Findings VII -3, VII-4, VII-5 and VII-25)
VII-7	Establish a traditional transmission utility system planning function that results in industry accepted planning products such as: system-wide studies not just area

	studies; five-year, ten-year, 15-year and 20-year system layouts; integrated ten to twenty year system plans; and timelines of system needs. (Refers to Findings VII-8, VII-11, VII-13, VII-24, and VII-26)
VII-8	Evaluate the boundaries for continuity between the integrated transmission and the integrated distribution plans to assess whether the entire "wires" business is adequately planned. (Refers to Finding VII-8, VII-10, VII-13, and VII-25)
VII-9	Adopt a results oriented approach to drive the development and implementation of asset management strategies by their relationship to equipment failure causal factors and system performance. • Prioritize asset management strategies by their relationship to outage causal factors and their ability to directly affect reliability performance measures. • Evaluate this stratification annually to maintain focus. • Differentiate long term asset strategies from those dealing with specific reliability problems and their incorporation into the annual system plans. • Evaluate the effectiveness of asset management strategies in terms of the number of capital projects and maintenance programs actually executed. (Refers to Findings VII-18 and VII-25)
VII-10	Initiate or partner with NYISO on appropriate studies regarding the effect and needed response to increased application of Distributed Generation, Renewable Resources, SMART GRID and other trends in utility system operations. (Refers to Finding VII-19)

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	Bruce Walker, VP Asset Strategy & Policy

Background Information

System planning by electric utilities in New York is marked by a combination of differing jurisdictional responsibilities – involving the NYPSC, the New York Independent System Operator (NYISO) and the Federal Energy Regulatory Commission (FERC). It is also affected by emerging new energy-markets and technological change. In particular, the NYISO planning process continues to mature and the NYISO is asserting its role as the coordinator and integrator of utility transmission plans and as a principal participant in the project approval process. NG has the additional complexity of having two separate organizations performing system planning studies – U.S. Transmission for transmission projects and the Electric Distribution &Generation Line of Business for sub-transmission and distribution projects. However, the Company is partially addressing this issue because it has already undertaken and begun an integration of the Transmission and Distribution lines of business in the United States – resulting in an Electric Operations Organization. While, the asset management / planning functions will exist in both the new Electric Operations Organization and the US Transmission Organization, they will be working towards aligning their processes and increasing coordination as outlined in our response herein.

National Grid uses an "asset management approach" to reliability planning for both its transmission and distribution systems. While the U.S. Transmission Asset Management groups have appropriate policies and procedures for the types of studies to be performed, the policies focus on coordination in the study process among participants from the various groups and on the development of plans.

The Transmission Asset Management organization is chartered with developing asset-specific programs, projects, spending and resource work plans, and budget. While National Grid has developed a number of regional transmission studies, it has not combined those studies into a single capacity plan. National Grid uses a similar asset management process for the distribution network as it uses for the transmission system. The distribution network strategy organization has appropriate policies and procedures for conducting system studies in place. NMPC's service territory has had a system reliability problem for many years but has made significant improvements during the last three years resulting in the Company exceeding its reliability metrics during the last two years. While the company's approach to distribution reliability planning is appropriate, it has not yet developed a master distribution plan nor has it produced a comprehensive reliability plan. The processes used by Transmission and Distribution will be better aligned as the organization transitions to integrating many of the Transmission and Distribution organizations.

National Grid utilizes an objective scoring system to prioritize both transmission and distribution capital projects. Projects approved by the two organizations are appropriately justified and there is sufficient governance. However, they are identified and approved in an incremental process which can be improved upon by the development and execution of an integrated transmission and distribution system plan and thus, the implementation plan set forth by the Company in this section is focused on driving that result.

Proposal to Implement Recommendation

National Grid will develop an integrated NMPC Transmission and Distribution Strategic System Plan (SSP) which will cover a fifteen year timeframe and will be updated annually (Recommendation VII-7). The strategic plan will be divided into discreet time periods e.g. short term (0 to 5 years), medium term (6 to 10 years) and long term (11 to 15 years). The SSP will directly link Company objectives through to an executable system plan in New York. It will do this by evaluating where the system is today and defining where we envision the system evolving to; identifying key drivers and influences that will affect our opportunity to enhance the overall system.

As might be expected, the short term initiatives will appropriately focus on maintaining system reliability while the medium to long-term plans will address broader trends recognizing that events may alter these trends as time passes. Accordingly, short term plans will be made with more specificity and clarity regarding impact to customers and medium to long term plans will be more comprehensively designed For example, the degree of confidence in any System Capacity & Performance projects will be lower in the medium to long-term due to the range of uncertainties around changes in demand, sources of generation and events currently unforeseeable; for example, a sudden decline in the world economy or increased load growth in certain geographic areas.

The Company will develop a combined Transmission and Distribution Strategic System Plan for April 2011 and each year thereafter, and would propose that plan as a replacement for the Report on the Condition of Physical Elements of the Transmission and Distribution Systems (previously filed in October) and the Capital Investment Plan (CIP – previously filed in January) filings. The SSP will incorporate the information that was previously provided in the two plans mentioned and further include the necessary detail required by an integrated system plan. This April submission allows the Company to provide the best information regarding the actual levels of investment in the system because it aligns with the internal budgeting processes utilized by National Grid. Moreover, the development of the Strategic System Plan will be ongoing with subsequent improvements anticipated year on year consistent with the needs of the system.

The SSP will compliment the integrated state-wide stakeholder driven transmission planning processes mandated by FERC in Order 890 and required by the tariffs of the New York Independent System Operator, Inc. Accordingly, the Company envisions this process as supplementing and drawing from the NYISO planning process rather than duplicating it (Recommendation VII-1).

National Grid will modify its annual planning process to ensure that the SSP evaluates a high level review of the entire system and the work developed at a regional level. Additionally, the annual SSP will specifically incorporate information that will provide a holistic view of industry / state-wide issues.

This ongoing process will result in a Strategic System Plan that ensures Transmission and Distribution capacity, reliability and asset plans/programs are reviewed together and result in a single plan that suits the needs of our customers and stakeholders (Recommendation VII-8).

The Implementation Plan will specifically review methods to use information derived from annual operational reports such as the Transmission System Reliability Performance Report and the Distribution Reliability Report or other such reports as the Company feels are appropriate in order to establish clear links to the drivers for the Strategic System Plan (Recommendation VII-2). As part of its SSP and as a result of incorporating the Report on the Condition of Physical Elements of the Transmission and Distribution Systems and the Capital Investment Plan into the SSP, the Company will be able to demonstrate this link. Additionally, the Company will consider a range of appropriate solutions to identified needs and evaluate which solutions provide the most efficient, long-term investment for the benefit of customers. Specifically, the System Strategic Plan will include a chapter on reliability trends over the past 3 - 5 years. The Company notes that the relationship between capital programs and system reliability is probabilistic rather than deterministic and, accordingly, must be measured over periods of at least three to five years for such analyses to be meaningful. As part of the Implementation Plan, the Company will establish processes to improve the use of system trend data as inputs to asset health/strategy and recommended projects.

The annual Strategic System Plan will include an assessment of investments made previously, recognizing that in some cases the evaluation will focus on trending data. This evaluation will focus on reliability, capacity and asset specific initiatives (Recommendation VII-3). The annual SSP will, where possible, also incorporate economic evaluations that will determine the relative efficiency of programs and explore alternative opportunities. The primary focus of this will be on system capacity and performance programs and asset condition programs; as opposed to more non-discretionary investments like adding new customers onto the system (Recommendation VII-5).

As part of the Implementation Plan, Asset Management Strategies will be reviewed and revised accordingly over a two-year period beginning in January 2010. The review will focus first on those asset strategies most impacting reliability performance so as to best influence the short term opportunities incorporated into the short term SSP. Longer term strategies will be reviewed and incorporated into the SSP as required (Recommendation VII-9).

National Grid will continue to track, manage, and reserve for unidentified, mandatory and high priority projects, "walk-ins", as part of its investment planning and current year spending management processes. These projects will be included as part of our quarterly reports submitted to the Commission. The reporting will include the addition of the project spending rationale to better indicate whether the project is mandatory or non-mandatory in nature. Project cash flows and priority scores will continue to be provided.

National Grid has already adopted a preliminary monthly report to capture and evaluate the impact of project "walk-ins" and "walk-out" information. We will discuss with the Commission incorporating this information in to the quarterly report. (Recommendation VII-4). Additionally, National Grid will include a section in the SSP that addresses lessons learned and actions taken with respect to these opportunities.

As part of the SSP, National Grid will evaluate outage types and trends that were avoidable due to improved system planning (capital) and preventive maintenance (O&M) such as vegetation management and failed equipment, noting; that the Company will evaluate outages based upon system trends recognizing that:

- The relationship between both increased capital spending and increased O&M on the one hand, and reliability on the other hand, is probabilistic rather than deterministic, meaning that it is not possible to predict in advance what individual outages will be avoided by any particular level or type of investment, or conversely if a given level of investment or O&M would have prevented an outage; and

- Vegetation outside the Company's rights-of-way is beyond the Company's ability to control.

Furthermore, National Grid will utilize a "cause code" analysis to evaluate outages. As a result, National Grid will incorporate this analysis into its annual SSP and identify program investment and the expected benefits that will be evaluated to measure the effectiveness of the program. (Recommendation VII-6).

As part of the SSP, National Grid will determine how to meet future demands placed upon the system including providing long term secure and sustainable energy supplies. This plan will consider both existing and emerging technologies including the impacts of greener renewable sources of energy (e.g. wind, solar) as well as looking to see how National Grid can position itself to take advantage of these opportunities. National Grid is already very active in the promotion of integrating renewable energy sources within the planning process. National Grid is participating in the NY STARS study and is actively engaged in many of the NYISO planning processes including the CSPP, RNA, CARIS as well as special studies such as the NYISO Wind Study. National Grid is also working with the NYISO and other Transmission Owners on implementing Phasor Measurement Units and installing capacitor banks as part of NYISO's successful stimulus proposal to the DOE. In addition National Grid has provided comments on the NY State Energy Plan (Recommendation VII-10). Lastly, National Grid commissioned a team of individuals from the planning functions, regulation and customer service to review methods for evaluating non-wire alternatives to investments. This team continues to make progress and will continue its effort during this year.

Update 1 Changes

Schedule and progress updates appear below. The update also reflects addition of a major activity/milestone relating to implementation of the recommendation on performance of economic studies (VII-5).

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Deliver Integrated NMPC Transmission and Distribution Strategic System Plan. (SSP) (VII-1)	February 2010	April 2011		~~Planned~~The draft report has been initiated and studies are currently in progress that support development of the strategic plan as per the schedule.
Develop a schedule for completing the Implementation Plan as set forth herein for filing a SSP by April 2011.	February 2010	February 2010	Complete 03/2010	~~Planned~~Complete, schedule has been developed.
Determine process to	February 2010	September		~~Planned~~In progress

review methods to use information derived from annual operational reports. (VII-2)		2010		
Project Walk-in Report – Addition of Spending Rationale Classification and incorporation of project walkout information. (VII-4)	April 1, 2010	May 15, 2010		~~Planned~~On schedule and working - Transmission and Distribution are providing a revised definition on walk-ins/walkouts and have committed to the addition of Spending Rationale Classification and the incorporation of project walkout information into the quarterly report to the PSC. Walk-in report was provided in 4th Quarter Report for FY2009-2010.
Perform economic studies to identify more efficient system modifications that can reduce the costs of service and increase utilization of resources. (VII_5)		Dec-10		~~Planned~~This is included within the methodology of doing studies as well as within the system-wide studies, an analysis of alternatives would be performed including DSM/EE and other wires alternatives. (this deliverable is part of overall plan deliverable). Model to be completed by year-end and studies will be ongoing.
Develop process in order to evaluate outages that were avoidable due to improved system planning and preventive maintenance. (VII-6)	February 2010	December 2010		~~Planned~~Expected to be completed by December
Incorporate the results of a traditional transmission utility system planning	February 2010	April ~~1,~~ 2011		~~Planned~~The draft report has been initiated and studies are currently in progress that support

function. (VII-7)				development of the strategic plan as per the schedule.
Establish the boundaries for continuity between the integrated transmission and the integrated distribution plans. (VII-8)	February 2010	December 2010		~~Planned~~Boundary Definitions are nearly complete for New York. On track for completion on or ahead of schedule.
Adopt a results oriented approach to drive the development and implementation of asset management strategies by their relationship to equipment failure causal factors and system performance. (VII-9)	February 2010	September 2010		~~Planned~~Expected to be completed by September.
Initiate or partner with NYISO on appropriate studies regarding the effect and needed response to increased application of Distributed Generation, Renewable Resources, SMART GRID and other trends in utility system operations. (VII-10)	Ongoing	Ongoing	Complete 01/2010	National Grid is participating in the NY STARS study and is actively engaged in many of the NYISO planning processes including the CSPP, RNA, CARIS as well as special studies such as the NYISO Wind Study. National Grid is also working with the NYISO and other Transmission Owners on implementing Phasor Measurement Units and installing capacitor banks as part of NYISO's successful stimulus proposal to the DOE. In addition National Grid has provided comments on the NY State Energy Plan. Participation will

				be ongoing.
Asset Management Strategies will be reviewed and revised accordingly over a two-year period beginning in January 2010.	January 2010	January 2011, January 2012		To be done in the last quarter of the calendar year.

Summary of Cost/Benefit and Risk Analysis

Estimated need for 6 additional FTEs and $20,000 in Information System upgrades for all recommendations in System Planning. This covers recommendations VII-1 through VII-6 and VII-8 & VII-9.

Two FTEs, and $500,000 of IT systems in asset management ($250k in FY11 and FY12 respectively) to address recommendation VII-7.

Measures of Success

As part of the Implementation Plan the Transmission and Distribution Asset Management organizations will develop appropriate key performance indicators to appropriately evaluate the success of the development and execution of the SSP consistent with the Line of Sight goals.

F. Program and Project Planning and Management

Recommendation VIII-1

Ensure that projects are managed in accordance with PMP requirements.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	~~Andy Hibbitt~~David Way, Vice President Project Management and Construction ~~Work Delivery~~

Background Information

The Project Management Playbook (PMP) intent is to improve National Grid's ability to plan, engineer, design and construct capital projects on time, on budget, and within scope and quality requirements. This will be accomplished through enhanced project management processes, procedures, roles, and measurements that are adopted and embraced universally by our organization. The Company's implementation of actions to meet this recommendation will be coordinated with our actions to meet similar recommendations in this chapter.

The PMP was rolled out in Fall 2007 and projects underway were individually assessed to determine whether there was any added value to implementing the procedure at that stage of the project life cycle. All projects initiated after the roll out of the PMP that meet the criteria defined in the PMP, are being managed in accordance with this procedure. Projects that do not meet the criteria are managed on a portfolio basis.

Proposal to Implement Recommendation

National Grid will conduct an assessment of the criteria used to determine whether a project should be managed in line with the PMP. A formal guidance document will be produced that defines the criteria that will be used to determine what level of project management discipline should be applied to a project to provide a cost effective delivery model for each project.

For projects that do not require management in line with PMP a formalized delivery procedure will be developed and documented. This process will describe those elements of project management which are appropriate for projects which fall into the category.

Update 1 Changes

Updated team lead information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Publish criteria document that defines the level of project management discipline that will be applied to a project.	Apr. 2010	Sep 2010	-	~~Planned~~Draft proposal developed for review. Discussions ongoing with key stakeholders, including Program Mgmt and Asset Mgmt, with respect to the criteria used to determine the level of management.
Fully document process for non PMP managed projects.	Jan. 2010	Dec 2010	-	~~Planned~~Project has been kicked off with a cross functional team. Charter developed , 2 workshops held with focusing on playbook steps 1-5 to determine equivalent steps for non PMP managed projects.

Summary of Cost/Benefit and Risk Analysis

Managing projects in line with documented procedures will facilitate the efficient delivery of the Company's construction program. There will be no incremental cost associated with the implementation of this recommendation

Measures of Success

For all projects initiated after the modifications, there will be a clear understanding what level of project management discipline will be applied to the project and a continuous improvement in the delivery of projects.

Chapter VIII - Program and Project Planning and Management

Recommendation VIII-1-1

Make Quality Assurance an integral part of the project management process for both in-house and regional delivery venture work forces.

Implementation Plan Leads

Executive Sponsor	~~Andy Hibbitt, Vice President Work Delivery~~Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction~~Jim Staid, Director Work Program Management~~

Background Information

The Auditors review of the project files suggests that quality assurance is not a formal element of the project management process. Specifically, the audit report states that:

- Project files do not contain typical quality assurance documents such as:

- Quality assurance plans,
- Project management meeting minutes discussing the design and construction,
- Equipment physical inspection reports upon receipt,
- Construction inspection reports – concrete strength, field checks of conductor spacing, wiring continuity test.

- Transformer and relay test reports are typically included in project files.

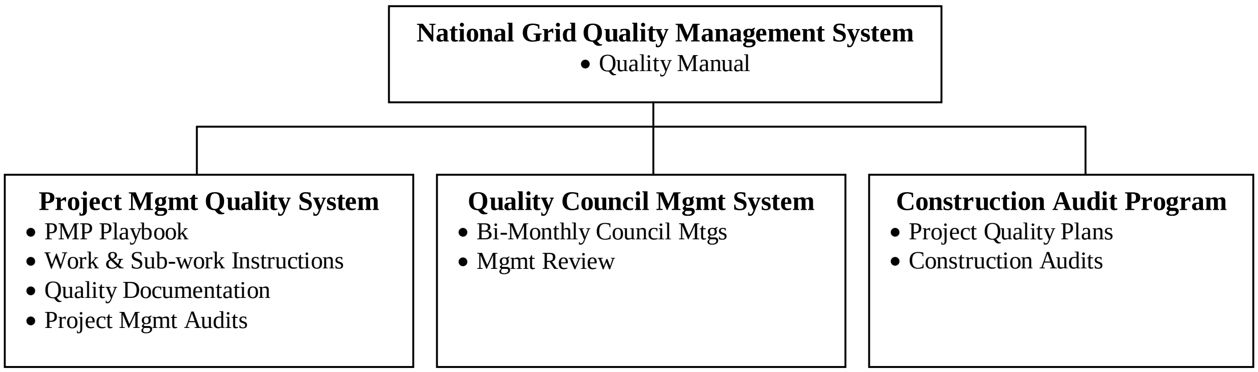
Proposal to Implement Recommendation

National Grid has recently established a discrete Quality Assurance (QA) team, as part of Works Program Management (WPM), and is staffed by a QA manager supported by an analyst and three auditors. The Group's mandate is to establish a Quality Assurance system which ensures the quality of the project's entire lifecycle, while driving continuous improvement.[3] Each RDV (Regional Delivery Venture) also has a Quality Manager as part of their senior management staff with a similar mandate.

The QA group's Quality Management System (QMS) will include the establishment of a Project Management Quality System (PMQS), a Quality Council Management System

[3] Transmission line and transmission/distribution substation project will adhere to the requirements of the Quality Assurance program.

(QCMS) and Construction Audit Program. The scope, requirements, authorities, responsibilities and documentation requirements of the QMS will be defined in the Quality Manual (QM) (Refer to Exhibit A: Draft Quality Manual). Specific procedures will be completed and referenced in the Quality Manual (i.e., Quality Audits, Document Control, Management Reviews, Corrective and Preventive Action Plans, etc.). Additionally, to promote proper communication and sharing of information, a Quality Assurance section (containing QA procedures, results of audits and all other pertinent QA information) will be added to National Grid's Sharepoint system for the use by all.



The Project Management Quality System is a system based on QMS and will include:

- PM Playbook describes the process that National Grid uses to delivery capital projects.
- Work and Sub-work Instructions will detail work processes and requirements for completing the various steps within the PM Playbook, i.e. "how we do it" vs. the Playbook's "what we do".
- Quality Documentation will define specific document control requirements for the many types of project documentation, including but not limited to any deliverables as required in the PM Playbook, i.e. Meeting Minutes, Project Estimates, Work Proposals, etc. A Project Management Work Information Tracker and a Scope Creep Analysis Tracker will be established which will further ensure the success of the quality project documentation.
- Project Management Audits will be internal audits conducted by the WPM-QA group which will assure that National Grid complies with the PMQS. A minimum of 24 audits are scheduled for each FY.

The Quality Council will be chaired by National Grid's Quality Assurance Manager, and include as its members each of the external RDV's Quality Managers and the Director of Construction from the internal System Delivery group. The mandate of the Council will be to establish a culture of quality, create QA synergies and share QA Best Practices across both the external RDVs and the internal System Delivery group. The Quality Council will establish:

- Bi-monthly Council Meetings will be held to promote best practices and innovation sharing between the external RDVs and the internal System Delivery group. Bi-monthly meetings commenced April 2009 and four meetings have been held since the April meeting.

- Quality Council Manual will be established which will define the scope, requirements, authorities, responsibilities and documentation requirements of the Quality Council.
- Management Reviews of the Quality Assurance program will be held periodically (annually at a minimum). The Quality Council will present to management the current status of implementation, goals achieved, Best Practices and future directives. Management attendees will include the Director of WPM, VP of Work Delivery, and senior management at each of the external RDVs and the internal System Delivery group.

The Construction Audit Program will focus on the construction processes, site controls and physical structure, validating the expected life-cycle of the asset. This Program will largely be defined by Transmission Line Specifications SP.06.01.301 and Substation Specifications SP.08.00.001. Each RDV, the internal System Delivery group and all sub-contractors will be included in the Construction Audit program. Construction Audits are evenly distributed across each RDV and the internal System Delivery group.

- Project Quality Plans will be required for each project and will define relevant project documents, project specification requirements, construction method documents, and site specific quality requirements.
- Training on the requirements of Step 3 of the PM Playbook will be scheduled for all Construction Supervisors, both external RDV and internal System Delivery. National Grid's Director of Construction will lead the training sessions, scheduling one session in New England and one in Syracuse.
- Construction Audits will be rated by four possible categories: Acceptance Observation, Minor Finding or Major Finding. Construction Audits will be completed by National Grid's QA Group's QA Auditor.[4]

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start	Estimate Completion	Actual Completion	Current Status

[4] (1) Acceptance is conformance to requirements. (2) Observation is not a finding and has no affect on the grading of the audit, but a recommendation of improvement. (3) Minor Finding is a correctable item, will be responded to within 30 days, and will be verified by National Grid. (4) Major Finding is a non-conformance, affecting process, design or system specifications which could compromise the integrity of the project.

	Date	Date	Date	
Project Management Quality System				
Quality Manual	7/2009	3/2010	Complete 03/~~01~~/2010	~~In Process~~Complete
PM Playbook Work & Sub-work Instructions	7/2009	3/2010	Complete 03/~~01~~/2010	~~In Process~~Complete and is currently in use within the PM Playbook
Project Mgmt Audits	3/2010	On-going	Complete 04/~~01~~/2010	Complete and on-going
QMS Testing & Gap Analysis	4/2010	12/2010		~~Planned~~Kick off meeting held
Quality Council				
Bi-Monthly Quality Council Meetings	4/2009	On-going	Complete 04/~~01~~/2010	Complete and on-going
Construction Audits				Complete

Summary of Cost/Benefit and Risk Analysis

Balancing the "Cost of Quality", (QA department and associated expenses) will be a positive variance versus the benefits of a documented, traceable, quality management system when the metrics of the projects provide deployment of continuous improvement teams to reduce cost, add efficiency, reduction and/or elimination of non-value added operations/functions, and reduce delivery time to completion of projects.

Playbook audits will provide an evidence gathering tool that is used to evaluate how well we are meeting our requirements. This validation will confirm that defined requirements are being achieved.

The construction audits validate the process during the "production phase", rather than the "inspect after it is completed". The construction audit also confirms that our contracted and internal RDV's have validated the life cycle of the asset by confirming that National Grid specifications are being met. The lessons learned/continuous improvement program will be implemented using trending analysis compiled through a robust auditing program.

Measures of Success

The documented QMS work instructions will provide a roadmap to project managers on fitting the universe of projects into one process guide, the playbook.

The work instructions will provide a training tool, documented project requirements, and an auditable system that will withstand an outside independent audit.

Measures of success will include a decrease in the number of observations, major and minor findings, a decrease in repeat do-over work, a decrease in cost-overruns and delay in schedule.

Chapter VIII Program and Project Planning and Management

Recommendation VIII-1-2

Have project managers actively monitor overall project progress against the baseline schedule and review cost versus progress and budget. (Refers to Finding VIII-11)

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction~~Andy Hibbitt, Vice President Work Delivery~~

Background Information

The auditors considered that there was no demonstration of active monitoring and reviewing of projects. Some of the projects selected for analysis by the auditors included ones managed though a number of historical systems rather than current ones.

Proposal to Implement Recommendation

To allow Project Managers (PM's) to actively monitor overall project progress against baseline schedules and to review project costs against schedule and budget requires a link between cost and schedule. In this regard, National Grid is evaluating changes to processes and procedures. Initiatives that are underway provide project managers with new tools to monitor their projects, including: Estimating Center of Excellence (ECoE), Project Controls/Reporting, Primavera Version 6 implementation and the development of new Work Breakdown Structure (WBS) /Cost Breakdown Structure (CBS).

Estimating (Reference recommendation 3 & 4)

National Grid has established an ECoE to focus on estimates for projects involving distribution lines. The ECoE is also providing common tools and processes for use on substation and transmission line projects. The ECoE provides distribution engineers and designers with robust tools and information to prepare estimates commensurate with the desired accuracy throughout the projects lifecycle based on the maturity of the project.

For Distribution, the employment of dedicated distribution line estimators will be determined by project level and complexity. This decision will be made following the full implementation of the ECoE. Based on this evaluation, if dedicated distribution line estimators are determined to be required, following ECoE implementation, it would require a staff of four estimators; three in Distribution, and one dedicated to TxD projects.

For Transmission line and T&D Substation projects, Transmission Line Engineering (TLE) has hired two full time estimators and T&D Substation Engineering & Design (SED) is in the process of recruiting two full time estimators and is anticipated to be in place in 2010.

National Grid's System Delivery group that delivers a portion of the Transmission Line and T&D Substation capital plan has also hired professional estimators. As of January 4th 2010, the group is fully staffed and consists of four full-time estimators.

The detailed implementation plan is in recommendation VIII 3 and 4

WBS/CBS (Reference recommendation 2)

The fundamental framework for project controls is created by aligning the CBS to the cost estimate, setting the information out in an integrated way with the deliverable based WBS. A robust WBS / CBS structure is being established by creating a direct mapping between the set template WBS structure and CBS categories. This mapping will ensure that projects will be scheduled in the same way from project initiation to project close out, allowing for projects to be viewed in a consistent format, and also allowing budgets to be aligned to this standardized structure of project deliverables. In turn, this allows for a roll up/drill down of project deliverables in direct alignment with the time profiled project estimate/cost data held in Primavera.

In a portfolio view, projects can be grouped or directly compared against each other, using the same WBS / CBS structures and summary information. This allows for consolidated project or program management reporting and also for cost control purposes. These standardized structures create a consistent enterprise view across projects and is key to effective management of the Portfolio.

The budget and schedule are fundamental to the control process. It is against these two elements the progress of the project activities, and the production of the deliverables is measured. This is achieved by combining information on schedule, budget, project deliverables and utilizing earned value analysis.

The detailed implementation plan is in recommendation VIII 2

P6 implementation (Ref Chapter VIII-recommendation 2)

With the implementation of Primavera 6, the Program Management group at National Grid will have a program view of overall resource and project requirements for both current and future year work. Program Management will move into a better position to provide support and performance reporting on National Grid's resourcing and implementation plan. The Primavera system will support the planning and the movement of internal and external resources as required to meet work plan targets and milestones. Effective resource planning requires and overall concentration on improving project visibility, governance, accountability, and responsibility to the entire work implementation plan regarding total project cost, scope, and schedule inclusive of budget adherence. The implementation of

Primavera utilizing the newest version and configuration will provide improvements by driving the visibility of the work plan deeper into the organization via the WEB capability and also provide visibility of "ball in court" during the project life cycle. The WEB capabilities of Primavera P6 will also facilitate improved project team communications and information exchange to better deliver the planned work. The implementation of Primavera version 6 will provide National Grid a better platform from which it can provide improved project management and reporting.

The detailed implementation plan is in recommendation VIII 2.

Project Controls (Reference recommendation 2)

Estimates for T&D substation and Transmission line projects will feed data into the Project Controls team for more robust project level reporting. Project control reports are under development aligning with efforts underway in the areas of estimating and scheduling; the goal is to report against a consistent set of costs in the estimate, sanction paper and the "actuals" on a monthly basis.

Project Controls and the associated reporting will strive for a consistent reporting format which may be aggregated and summarized at various levels dependent of the size and complexity of projects. The application is currently excel-based with the goal to automate the process through the use of an enhanced Primavera platform currently being implemented.

The cost components tracked in the reports will be linked to the project schedule and WBS which is baselined. Actual costs from National Grid financial systems will be mapped to these cost components for comparison against the plan. This will enable accurate reporting of Earned Value, Cost Performance Index (CPI) and Schedule Performance Index (SPI).

The detailed implementation plan is in recommendation VIII 2.

Update 1 Changes

Updated team lead information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Formal project reviews at governance boards	April 2010	N/A	Complete 04/2010	~~Planned~~Complete. Will continue with Capital

				Investment Group (CIG), Asset Management Investment Committee (AMIC) Transmission Investment Committee (TIC), and Distribution SRAC.
Formal monitoring of non PMP projects	Jun 2011	N/A	=	Planned

Summary of Cost/Benefit and Risk Analysis

Greater scrutiny of all projects and enhances project controls processes will lead to more accurate forecasts and tighter control of project deliverables.

Measures of Success

Post project reviews will identify compliance with original project deliverables; interim project reviews will also provide levels of confidence in the process being followed.

Chapter VIII Program and Project Planning and Management

Recommendation VIII-1-3

Adhere to policies and procedures regarding project cost control and re-sanctioning requirements. (Refers to Finding VIII-19).

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction~~Andy Hibbitt, Vice President Work Delivery~~

Background Information

Corporate governance processes for re-sanctioning of projects are maintained in Transmission Group Procedure 11 (TGP11) and Distribution Asset Management 006A (DAM006A).

As part of standard company compliance with Sarbanes Oxley legislation monthly assessments of cost control against sanctioned amounts are carried out.

The Company's implementation of actions to meet this recommendation will be coordinated with our actions to meet similar recommendations in this chapter.

Proposal to Implement Recommendation

The investment management procedures with respect to sanction and re-sanctioning are in existence and are a requirement for all staff. Training will be provided to all staff involved in the management of project delivery.

This training will include actions to be taken to maintain the company's compliance with Sarbanes Oxley legislation, including the provision of monthly reporting and reviews.

Update 1 Changes

Updated team lead information is reflected above. Schedule and progress updates appear below.

Schedule

Major	Estimated	Estimate	Actual	Current Status

Activities/Milestones	Start Date	Completion Date	Completion Date	
Roll out Training for all staff involved in management of project delivery.	April 2010	Jun 2010	=	Review and rollout began in May 2010 with expected completion in June. Formal training records will be retained in PeopleSoft.~~Planned~~

Summary of Cost/Benefit and Risk Analysis

There are no incremental costs associated with implementing this action. Implementing this action will ensure compliance with Sarbanes Oxley legislation.

Measures of Success

Ongoing monitoring will determine whether all projects are compliant with authorization procedures through the existing monthly reporting process.

Chapter VIII Program and Project Planning and Management

Recommendation VIII-1-4

Maintain comprehensive project management files. (Refers to Finding VIII-4)

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction~~Andy Hibbitt, Vice President Work Delivery~~

Background Information

The Project Management Playbook (PMP) intent is to significantly improve National Grid's ability to plan, engineer, design and construct capital projects on time, on budget, and within scope and quality requirements. The PMP was designed to manage larger, more complex projects and was not considered to be a cost effective procedure for all projects within the business plan particularly with smaller, short cycle projects.

Projects selected for analysis by the auditor were not all expected to be managed in accordance with the PMP or had been active prior to issue of the PMP. The audit recognizes that "two most recently initiated projects were fully documented in accordance with PMP".

The Company's implementation of actions to meet this recommendation will be coordinated with our actions to meet similar recommendations in this chapter.

Proposal to Implement Recommendation

A cross-functional team will:

- Review and determine appropriate retention requirements for project documentation. This review will allow differing levels of project documentation consistent with the levels of project complexity.
- Develop policy for employees' use defining project documentation requirements and their associated storage mediums/locations.
- Train staff on the new policy.

Update 1 Changes

Updated team lead information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Complete review and develop~~.~~ policy for retention requirements for project documentation.	Apr 2010	Oct 2010		~~Planned~~This activity is being coordinated with other initiatives associated with documentation management. A meeting has been held to establish the core team, team lead, and objectives for the initiative. Kick off and formal meeting schedules are in place.
Training staff on the new policy	Jan 2011	Jun 2011		Planned to start after policy documentation has been approved and published.

Summary of Cost/Benefit and Risk Analysis

The policy will ensure project management files can be referenced during and/or after the project life cycle. There will be no incremental cost associated with the implementation of this recommendation

Measures of Success

Efforts to refer and/or obtain project documentation at any given time will be further improved.

Chapter VIII - Program and Project Planning and Management

Recommendation VIII-2

Implement a Work Breakdown Structure (WBS) system to organize and manage projects. Use of a WBS should improve project cost and schedule management, monitoring, reporting, and feedback. (Refers to Finding VIII-13)

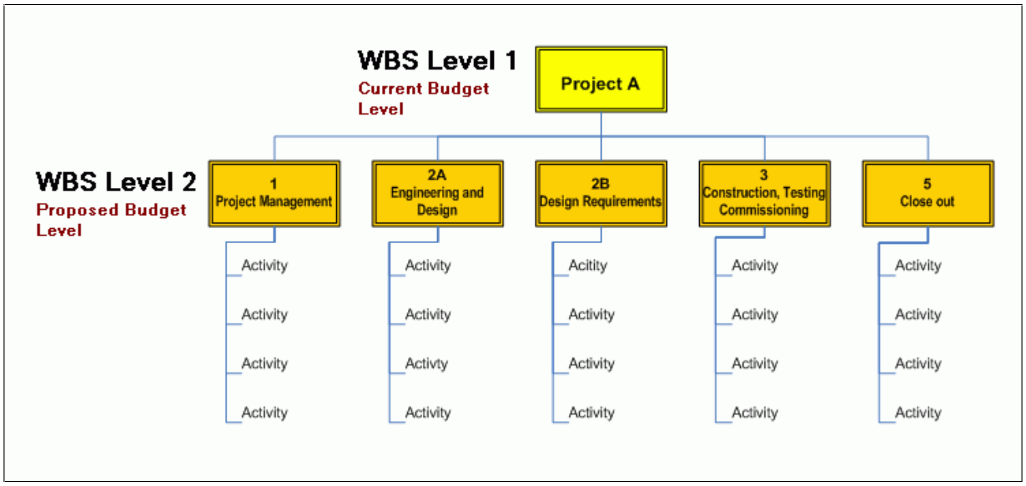
Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction

Background Information

NG has traditionally used a WBS structure organized by Phase (PMBOK 5.3.2.1) with the degree of workout and detail of the sublevels at the discretion of the Project Manager. Historically the amount of detail contained in the WBS has primarily been directly related to complexity of the project and to a lesser degree the familiarity and comfort the project team has had in using the Primavera system.

NG has also customarily budgeted and tracked costs at the project level or Level 1 of the WBS (see fig. 1). Budgeting and tracking at Level 1 represent the total project costs. This high level method has inherent limitations on budget and cost management. It is always desirable to capture and track cost and budget at the lowest possible level of detail; however, without integrated financial and project management systems the manual data entry level of effort has been prohibitive to date at both a manpower and cost basis.



Proposal to Implement Recommendation

Presently NG is in the development and testing stages of programming a new financial to Primavera interface. This interface will facilitate the ability to capture resource hours and costs, as well as internal overheads and invoices to a secondary WBS level. The specifications of the interface are based on the use of the current Phase WBS structure. With this interface it will be possible to both budget and collect project costs consistently at a Level 2 WBS on select projects. To comply with the audit findings, National Grid will perform a Best Practices review to determine the appropriate level of WBS structure required by project type. Also a current systems review will be conducted to determine if the reporting functionality of the various IT systems will be impacted by a change from the current WBS. Currently National Grid's financial systems support cost tracking at the individual activity level. Costs will be captured and tracked at the resource grouping or Department ID. The current configuration of National Grid financial systems limits the granularity obtainable in cost and budget data. However; the interface will provide improvement in data for monitoring project cost, schedule management and reporting. Project WBS structure and activity detail is planned to be reviewed during the interface development. Currently the interface is expected to be available with the Primavera P6 system rollout for the FY11 work plan in April of 2010.

In addition to the above work, a comprehensive review of Primavera version 6.2, associated applications and financial systems is being undertaken to identify a more comprehensive project controls reporting solution.

Update 1 Changes

During February and March 2010, the National Grid Primavera P6 Implementation team decided on achievable implementation objectives in the near term considering all known practical limitations, such as current financial reporting practices and the current proficiency of the P6 user population. The current financial system will report the project cost to an aggregate level that aligns with a Level 2 WBS; at this time, further WBS detail is not practical. The decision was made to continue standardization to a level two WBS representing the National Grid Project Management Playbook steps. Decisions regarding WBS standardization to Level 3 will be reviewed after further financial data is available for a more thorough assessment and any limitations can be better determined and evaluated.

On March 30, 2010, the in-flight projects for the Distribution Line group went live in the new National Grid Primavera P6.2 Enterprise environment. The approximate 740 projects went through an electronic conversion process lasting approximately 5 days. The projects did not have the required coding for the financial interface or a completely standardized WBS structure. This work is required to be done manually and is on going at this time.

Substation and Transmission Line projects will be converted after evaluation of the Distribution Line process results. This schedule provides additional time for the more complicated Substation projects to be further refined prior to the conversion process. More importantly, the impact of when financial information is applied to the project can be evaluated. The evaluation of the financial information will provide insight to requirements and situations if a level 3 WBS is applied. The evaluation will likely require the revisiting of Best Practices and Processes. The application of the financials to the WBS will be run and evaluated through June.

In addition to the foregoing updates, updated team lead and executive sponsor information is reflected above, and schedule and progress updates appear below.

Schedule

- Continue with existing Phase 1, P6.2 Implementation Schedule as planned. Implement financial interface to Primavera as part of FY11 work plan as scheduled.
- Review the recommendation with the Program Management and Project Management groups. Perform best practice review, and system assessment.
- Develop requirements specification and develop Implementation Plan.
- Complete detail design and system plans.
- Develop training and/or job aid for the Program Management and the Project Management groups on conditions where the inclusion and the proper implementation of incremental WBS levels will improve the project cost, schedule management, monitoring and reporting.
- System/Process roll out, user training and verification testing.
- Final close out: update documentation and procedures.

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Continue with existing P6 rollout schedule.	on-going	~~April 2010~~ July 2010	-	Migrated to Phased Approach due to complexity. Distribution line completed, Substation and Transmission line forecast completion in July 2010.
Best Practices & System Assessment	January 2010	February 2010	Complete 03/~~10~~/2010	Complete.
Process and Systems Specification Requirements	February 2010	March 2010	Complete 03/~~10~~/2010	Complete.
Implementation Plan	May 2010	June 2010	-	On track for completion
Detail Design & Project Type/WBS Matrix	June 2010	August 2010	-	-
Systems Modification Plan	August 2010	September 2010	-	-
Training Plan and Job Aids	August 2010	September 2010	-	-
System Modification and Testing	September 2010	October 2010	-	-
User Training System Verification	October 2010	January 2011	-	-
Final Documentation & Close Out	January 2011	February 2011	-	-

*Time line will vary as more details are discovered

Summary of Cost/Benefit and Risk Analysis

No incremental costs or savings are specifically attributed to the implementation this recommendation because these improvements were initiated prior to the findings/recommendations of the audit.

Measures of Success

- Implementation of a standardized WBS
- Development and implementation of enhanced project cost, schedule management, monitoring and reporting.

Chapter VIII Program and Project Planning and Management

Recommendation VIII-3

Complete implementation of ECoE roles and responsibilities including establishing estimating tools, metrics and policies, creating estimating units and identifying and resolving areas of estimating deviations. (Refers to Findings VIII-16, VIII-18, and, and VIII-26).

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction

Background Information

The company does not employ a consistent, accurate process to develop engineering and construction project estimates. Thus, a single estimating data source, software tool, process, and feedback mechanism is needed. We have encountered spending plan development and project and portfolio management challenges in large part due to inaccurate project cost estimates. Further, project lifecycle estimates and revisions need to be coupled to the spending plan, project, and program management software programs.

Distribution project grade estimates are presently prepared by engineers and designers using National Grid's work management system. Investment and Conceptual grade estimates are developed using high level asset per unit costs contained in spreadsheets. Estimates are built by selecting the applicable packets of work ("compatible units"). The cost of each compatible unit is fixed in the work management system and spreadsheets.

Transmission line and transmission substation estimates are prepared for each individual project by engineers using tools and templates provided by each function. Transmission line estimates are prepared in an electronic spreadsheet based on a "compatible unit" methodology. Substation estimates are prepared in an electronic database by selecting the appropriate compatible units and their associated costs.

Proposal to Implement Recommendation

National Grid plans to make changes in its estimation processes by making organizational, process, data, and software improvements through its Estimating Center of Excellence (ECOE).

National Grid established an ECOE to focus on estimates for projects involving distribution lines, and the ECOE provides common tools and processes for use on transmission line and substation projects. Further, the ECOE provides engineers and designers with robust tools and information to prepare estimates commensurate with the desired accuracy throughout the projects lifecycle based on the maturity of the project. The ECOE has purchased a new estimating application (US Cost Success Enterprise) and is in the process of implementing it. Estimates will be developed using "estimating units," packets of work of a defined scope. These estimating units will be aligned with the desired accuracy for the estimate at each stage of the project's lifecycle; investment, conceptual, project, and delivery grade. The ECOE will maintain up-to-date per unit data of the material and labor requirements and cost of each unit.

For transmission line and substation projects, National Grid will employ professional estimators to validate the RDVs' cost estimates ("target prices"). The professionalism of the estimators will be demonstrated by their qualifications which may include education and training, estimating experience and estimating certification.

For Distribution line projects, National Grid will utilize the ECOE estimating tool and process to tailor each project lifecycle estimate type (investment, conceptual, project grade) to the groups and individuals responsible for and closest to the project at each lifecycle milestone. Through the ECOE, Distribution will also seek opportunities to develop the skills and professionalism of the estimators through education and training, estimating experience and estimating certification. A document describing how estimates are to be prepared by project teams is being drafted.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Implementation milestones are summarized in the table below.

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
US Cost Estimating Application	In progress	September 30, 2010		~~On-Going~~See below "Implement US Cost application"
Transmission Line Estimating Process	In progress	September 30, 2010		~~On-Going~~Draft process issued for comment in March
Implement US Cost application (including start of estimating variance analysis)	April 1, 2010	September 30, 2010		~~Implementation to begin following tool configuration and process finalization~~US Cost Application is live and in

				use as of 3/30/10. Distribution Planning is using for conceptual estimates on D Line projects. Data uploads and tool configuration for substations and transmission lines are in progress with implementation expected by September 30. Sub-transmission line estimates are expected to be available by September 30. Training for US Cost application in Distribution line was initiated in late January and is expected to continue through June. Training for substation estimating is expected to begin in June. Variance analysis with the new tool has not yet started.

Summary of Cost/Benefit and Risk Analysis

The distribution and transmission costs for ECOE software, staffing, and on-going maintenance is budgeted for under Transformation, department and functional maintenance budgets and are reflected in forward looking approved staffing levels. Since this is an effort underway before the Management Audit recommendations were published, the costs to establish the new department and software tools, as well as training are not incremental to current business plans.

Cost ($1000)						
IS Systems	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**NY or NY/NE**
None Incremental	$0	$0	$0	$0	$0	NY/NE
	Cost ($1000)					
Staff	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**Opex/Capex Split**
None Incremental	$0	$0	$0	$0	$0	NY/NE
Total	$0	$0	$0	$0	$0	

Measures of Success

National Grid will measure its success in the implementation of this recommendation by 1) the percentage of substation and transmission line project estimates where the RDV's target cost has been validated against the professional estimator's estimate in accordance with the established procedure and 2) the percentage of distribution line projects that are within estimating tolerances for categories of estimates prepared using the US Cost application.

Chapter VIII -- Program and Project Planning and Management

Recommendation VIII-4

Establish groups of professional estimators for US transmission and distribution that will develop estimates for planning, engineering and construction. Use these internal estimators to set and validate baseline estimates established for the RDV contractors.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction

Background Information

Distribution line project grade estimates are presently prepared by engineers and designers using National Grid's work management system. Investment and conceptual grade estimates are developed using high level asset per unit costs contained in spreadsheets. Estimates are built by selecting the applicable packets of work ("compatible units"). The cost of each compatible unit is fixed in the work management system and spreadsheets.

Substation and transmission line estimates are presently prepared for each individual project by engineers using tools and templates provided by each function. Transmission line estimates are prepared in an electronic spreadsheet based on a "compatible unit" methodology. Substation estimates are prepared in an electronic database by selecting the appropriate compatible units and their associated costs.

In anticipation of an increasing workload, National Grid has recently established contracts with two consortia that, along with its internal work force, will provide design and construction services for transmission line and substation projects for the next five to eight years. As part of the competitive tender process, rates for payment to each consortium were established. Further, estimates to perform a variety of representative types of work were provided. The internal delivery team is expected to provide similar estimates. These estimates will be used by the consortia and the internal delivery team to prepare project estimates.

Proposal to Implement Recommendation

National Grid has established an ECOE to focus on estimates for projects involving distribution lines. In addition, the ECOE also provides common tools and processes for use on substation and transmission line projects. The ECOE will provide distribution engineers and designers with robust tools and information to prepare estimates commensurate with the desired accuracy throughout the project's lifecycle based on the maturity of the project. The

ECOE has purchased a new estimating application (US Cost) and which it is proceeding to implement. Distribution line estimates will be developed using "estimating units," packets of work of a defined scope. The ECOE will maintain up-to-date estimates of the labor requirement and cost of each unit.

For substation and transmission line projects, National Grid will employ professional estimators to validate the RDVs' cost estimates ("target prices"). The professionalism of the estimators will be demonstrated by their qualifications which may include education and training, estimating experience and estimating certification.

A document describing how substation and transmission line estimates are to be prepared by project teams (which include either an RDV or System Delivery) and validated by National Grid has been drafted and has received preliminary executive approval. In summary, the procedure calls for the RDVs' target prices to be compared to estimates prepared by the professional estimators. Differences between the estimates and target costs that exceed allowable tolerances must be adequately justified by the RDV and agreed to by National Grid. Differences without sufficient justification may be rejected. Additional work is required before the process can be fully implemented, including completion of the US Cost estimating application and the creation of standard estimate formats.

For distribution line projects, the following approach, with underlying considerations, is being implemented.

Distribution line's estimating methodology reflects that distribution line estimating is driven by the wide variation of distribution project scope, cost, complexity, scheduling, materials, and construction and municipal regulations and practices. It is not cost efficient or practical to utilize a single estimating group to prepare estimates for all construction over such a wide spectrum of accuracy requirements, work types, and municipality breadth. However, all user groups will follow the ECOE policies, guidelines, tools, and processes. Procedures and tools will be configured such that estimate grade, timeliness, accuracy, consistency, and refinement are provided for under the ECOE responsibility umbrella. It will be the responsibility of each user group to apply the ECOE tools and processes and the responsibility of ECOE to ensure that user groups are complying with the tools, and processes as well as to ensure the accuracy of such tools processes and to make improvements where warranted.

National Grid will utilize the ECOE estimating tool and process to tailor each project lifecycle estimate type (investment, conceptual, project grade) to the groups and individuals responsible for and closest to the project at each lifecycle milestone; i.e., Investment, Conceptual, Project, and Delivery grade estimates. Through the ECOE, Distribution will also seek opportunities to develop the skills and professionalism of those individuals responsible for project estimating through education and training, estimating experience and estimating certification. Distribution line projects with conceptual grade estimates greater than $1M are assigned project managers, and as such have additional resources available with which to support the development of scheduling, forecasting, and estimating details. STORMS estimates will be prepared based upon updated CU's provided through the ECOE support process. A document describing how estimates are to be prepared by project teams is being drafted.

As the ECOE based processes, tools, variance analysis, controls, and resources are employed; National Grid will evaluate the need for dedicated distribution line project estimators. The ECOE estimating tool and process will be used to develop each project lifecycle estimate type (investment, conceptual, project, or delivery grade). Distribution line projects between $100k and $1M could be assigned to an estimator for review and/or development, depending on their complexity. The final decision regarding the employ of dedicated distribution line estimators, and at what project level and complexity, will be made following the full implementation of the ECOE. Blanket level work will continue to be estimated and processed through the STORMS system at the work order level. Through the ECOE, Distribution will also seek opportunities to develop the skills and professionalism of the both groups of estimators through education and training, estimating experience and estimating certification.

National Grid estimates that there are approximately 120 new distribution and TxD line projects in NY per year of $100k or greater total estimated cost. Investment grade estimates would be developed by the Network Asset Planning group using the tools, processes, and information provided by the ECOE. Conceptual grade estimates would be provided by the estimating group as would a degree of support for the design/estimate in STORMS.

National Grid will review potential value from the use of professional estimators for its' distribution line projects. If dedicated distribution line estimators are determined to be required, following ECOE implementation, it would require a staff of 4 estimators, 3 in Distribution, and 1 dedicated to Transmission projects managed by Distribution. However, National Grid will be reviewing the value from professional estimators once it has established a record of achievement using the tools and training developed for its improved estimation protocol.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Issue transmission estimating process	In progress	September 30, 2010	Complete 05/01/10	~~Draft process complete~~Process procedure issued May 1, 2010

Hire professional estimators for substation and transmission line projects	In progress	September 30, 2010		~~Five estimators hired to date. Five~~Two estimators hired in Transmission Line Engineering and four estimators plus an estimating manager hired in In-House Construction. Two estimators are hired in Substation Engineering and are scheduled to begin work on June 1, 2010.
Implement US Cost application	In progress	September 30, 2010		~~Development in progress.~~ US Cost Application is live and in use as of 3/30/10. Distribution Planning is using for conceptual estimates on DLine projects. Data uploads and tool configuration for substations and transmission lines are in progress with implementation expected by September 30. Sub-transmission line estimates are expected to be available by September 30. Training for US Cost application in Distribution line was initiated in late January and is expected to continue through June. Training for substation estimating is expected to begin in June.
Determine Distribution line estimator requirements	September 30, 2010	November 30, 2010		To be initiated following ECoE implementation

Summary of Cost/Benefit and Risk Analysis

The incremental direct financial impact of implementing this recommendation is shown below. The figures exclude costs which have already been requested in the FY10/11 business plan. They also do not include an allowance for inflation. They include indirect costs.

Cost ($1000)						
IS Systems	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**NY or NY/NE**
US Cost	$0	$0	$0	$0	$0	NY/NE
	Cost ($1000)					
Staff	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**Opex/Capex Split**
Dist. line Estimators (if required)	$400	$400	$400	$400	$400	50% / 50%
ECOE	$0	$0	$0	$0	$0	50% / 50%
Total	$400	$400	$400	$400	$400	50% / 50%

Measures of Success

National Grid will measure its success in the implementation of this recommendation by 1) the percentage of substation and transmission line project estimates where the RDV's target cost has been validated against the professional estimator's estimate in accordance with the established procedure; 2) the percentage of distribution line projects with estimates prepared using the US Cost application; and 3) the variance of estimates from job conception to job completion.

Chapter VIII Program and Project Planning and Management

Recommendation VIII-5

Have Internal Audit or an outside firm audit the RDV joint venture and parent entities on a regular basis.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer~~Andy Hibbitt, Vice President Work Delivery~~
Team Lead	Kate Darwin, Director Regional Delivery

Background Information

The Regional Delivery Venture Agreement gives the Company rights to audit the RDV members as follows:-

"37.7 Each of the RDV Members acknowledges the right of the Company and the other RDV Members or their representatives to inspect and audit any information record or account relevant to any Actual Cost or the RDV's or any RDV Member's overhead."

The Management Audit finding VIII-23 recognizes that while National Grid has contractual oversight and audit rights for the RDV and the RDV Member's overhead (the joint venture parent entities), it presently does not audit either entity. In the future, NG will have Internal Audit or outside firms audit the RDV joint venture parent entities on a regular basis."

Proposal to Implement Recommendation

The Company assumes the recommendation intends that such audits would be scheduled and conducted in a manner consistent with Corporate Audit's existing policies, extend to the relevant entities and their operations, and be consistent with the Company's rights under the Regional Delivery Venture (RDV) contracts.

The Company has received approval and begun a Governance and Controls Review with the use of outside auditing firm. This audit will be focused on the overhead costs of the NY RDV.

Update 1 Changes

Updated executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Issue terms of reference ~~Undertake audit and issue final report~~	Dec 16, 2009 ~~Jan 2010~~	Jan 2010 ~~Mar. 2010~~	Complete Dec-09	~~In Process~~ ~~Planned~~National Grid's Internal Audit, with assistance from Ernst & Young, have conducted an RDV audit during the 4th quarter of FY2010 per the ToR (terms of reference) established in December 2009.
Undertake audit and issue final report	Jan 2010	Mar. 2010	Complete 05/07/2010	Complete final report is dated May 7, 2010

The Company will conduct further audits in accordance with its' Corporate Audit policies and procedures at appropriate periods in the future.

Summary of Cost/Benefit and Risk Analysis

The cost is estimated to be $85k. No risks are identified.

Measures of Success

Achievement of the proposal will be measured by the completion and acceptance of the audit with prioritized actions, owners and timescales. Actions will be closed out when demonstrably complete in line with Corporate Audit's existing practice.

Chapter VIII Program and Project Planning and Management

Recommendation VIII-6

Ensure that all capital work orders are closed to plant in-service (FERC Account 101) within 90 days of equipment being energized. (Refers to Finding VIII-25).

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer~~Andrew Hibbitt, Vice President Work Delivery~~
Team Leads	~~Chris Brouillard, Director Investment Management Network Strategy~~ ~~Tom Sullivan, Director Transmission Investment Management~~ ~~Lisa Figliozzi, Director Plant Accounting~~Pat Hogan, Senior Vice President Distribution Asset Management

Background Information

Current work order processing practices for distribution and transmission, line and substation work orders need improvement. As Finding VIII-25 indicates, a significant number of work orders across distribution and transmission remain open greater than 6 months after the work is completed. These open work orders could also reflect situations where the work order becomes restrained in Construction Work in Progress resulting in situations where we are accruing AFUDC and not depreciation, or, for Construction Completed Not Classified restraints, the amounts remain unclassified with regards to specific depreciation rates. In some instances, it may be necessary to transfer charges to expense if the work does not ultimately result in capital construction. In other cases, the work orders may be open for legitimate scheduling or accounting reasons.

Proposal to Implement Recommendation

The company has established two cross-functional teams to investigate the causes of open work order processing delays, make short term corrective recommendations, and initiate actions tied to accepted recommendations. The teams are also working to process the backlog of open work orders and to report monthly on the number of open work orders and progress.

A summary of the cross functional team short term proposals that have been implemented to date follows:

- Increased work order close-out $ tolerance thresholds to better correspond to % tolerance threshold and streamline close out,

- Periodic STORMS and PowerPlant exception reports, to identify the processing exceptions in both systems,
- Separately identifying expense-only as-builts on monthly basis,
- INFONET accessible reports of open or inactive work orders updated monthly,
- Enhanced as-built status and retirement units in STORMS to expedite work order closeout,
- Transformation restructuring – A Centralized Group was established for initiation of confirming work and the closeout of all work orders (previously done by Operations and Design in the field),
- Identified patch enhancements to the working version of PowerPlant, version 9, and enhancements available via version 10 to automate work order close out activities that are presently conducted manually.

NG plans to make corrections in closing work orders to plant in-service by undertaking the following steps as part of a comprehensive plan to address delays in work order processing.

- Complete a comprehensive review of open work orders at the various stages of processing, compile findings as to the major causes of work order delays in processing, recommend actions to eliminate or adequately mitigate the causes, implement the accepted recommendations, and develop tracking and reporting metrics. STATUS – The Company undertaken a review of the driving causes of open work orders. Based on these causes, the Company is initiating Power Plant application upgrades. The Company has also processed blocks of work orders delayed in processing due to capital and expense validation checks, clearing the work orders as they are checked. We will provide a summary update on work orders remaining open as compared to historical levels at the next update report.~~Underway~~
- Complete an evaluation of systems enhancements, including STORMS and PowerPlant, addressing the causes of open work orders. Include systems interface elements in the evaluation as well as changes to processing steps, validations, and tolerance thresholds. STATUS - The Power Plant system upgrade to version 10.2 is being brought forward for final evaluations and approvals. The current approach is to implement interim Power Plant upgrades in order to increase existing Power Plant version functionality while version 10.2 is being pursued. ~~Underway~~
- Evaluate modifications to guidelines governing work order processing and close out rules to streamline the processing of work orders through the accounting steps without sacrifice to the integrity of our reported information. STATUS - Changes to closing tolerances were instituted in order to reduce the number of work orders that remained in open status solely due to tolerance reasons.~~Underway~~

- Map the processing steps, and the groups and individuals responsible for those steps to determine if the responsible parties have the necessary information, knowledge, tools, and training to ensure that the work is processed timely and consistently. STATUS - This initiative will continue as Power Plant interim steps are implemented and is expected to continue during version 10.2 upgrade and ultimate conversion of back office systems to SAP.~~Underway~~

- Determine if the responsible groups have adequate staffing and necessary information to support the close out/exception resolution process. STATUS – Initiated. Final levels to be determined in part based on the results of the process mapping review and conversion to Power Plant 10.2.

  Identify types of work that often involve payment or reimbursement to the company for construction and therefore necessitate that the work order be kept open to accept payment, often for several quarters or longer. Recommend how to treat these categories of work orders with respect to processing, closeout, and tracking metrics. STATUS – Initiated. Certain categories of work, particularly those involving third parties, that will require that the work order be kept open in order to accept payment to or by the Company.

- Engage Northstar and Commission Staff as part of the implementation plan to clarify the recommendation drivers and to refine specifics and metrics with regards to implementing this recommendation. STATUS -- Evaluate need based upon progress update discussions with PSC Staff.~~Planned~~

- Develop the estimated scope, costs, schedule, metrics, and impact of the recommendations, individually and as a whole. STATUS - Underway. The Company is implementing Short-, Mid-, and Long-Term initiatives.~~Planned~~

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. The Company also provides the preceding specific updates on actions it is taking to address the timely closing of work orders. With improved understanding of necessary actions to implement the recommendations, the estimated completion dates have been revised. Schedule and progress updates appear below.

Schedule

National Grid estimates that it will take approximately six months to complete the details of the plan. In the interim, the open work order cross–functional team will continue with their work to evaluate and implement short term recommendations, close out the existing backlog of open work orders, and institute tracking and reporting metrics.

Implementation milestones are summarized in the following table.

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Short Term cross functional team initiatives	In progress	~~June 30, 2010~~ Aug 2010		~~On-Going~~Ongoing, expect completion in August. 6.1 and 6.1.2 thru 6.1.6 are underway, 6.1.7 and 6.1.8 are planned. IS Project Enhancement – As part of the short term initiatives Plant Accounting, IS and Powerplant Consulting have implemented in the test environment a number of patches to the current version of legacy National Grid Powerplant functionality to 1) improve error reporting (enhance our ability to detect most if not all errors on a work order prior to kicking out of CCNC or unitization, as opposed to the existing scenario where personnel need to analyze all feeder systems to figure out the multiple errors, one work order at a time) 2) enhanced alerts on errors 3) a metric report to assist with identifying timeliness of close-outs and 4) clean-up of a significant portion of the existing back-log. From this, Plant Accounting is planning to have monthly meetings to discuss the metrics and issues. Plant Accounting personnel have been traveling throughout National Grid

				to provide training for operations personnel regarding the asset accounting process.
Initiate Long Term Solutions Study	Feb 1, 2010	~~May 30, 2010~~ July 2010		~~Framework and key area for study developed~~The long term study has been initiated and is expected to be complete in July. The company is incorporating PowerPlant into its overall conversion to SAP for a back office requirements application. The approach under study would include a PowerPlant upgrade to version 10.2. The functionality afforded by V10.2 would include substantially enhanced capabilities to manage, process, and track completed work through CWIP (107), CCNC (106), and EPIS (101). The time to process completed work through each account is also reduced along with additional capability to identify and address exceptions leading to open work orders languishing in the system, awaiting correction or processing. Subsequently, plans will be drafted to apply the features of the selected back office and plant support applications to work order processing requirements. We expect the back office application, including a plant unitization

				application, to be placed into service beginning in 2011/12.
Present LT Study Recommendations and secure approvals	June 1, 2010	~~June 30, 2010~~ July 2010		Awaiting study results

Summary of Cost/Benefit and Risk Analysis

The estimated distribution, transmission, and shared services costs associated with this NYMA recommendation have not yet been finalized. Our current estimate for system modifications and resource additions, that are incremental to existing budgets, is $1.4M. Upon completion of the study, estimated costs will be categorized, finalized, and incorporated into department budgets.

Cost ($1000)						
IS Systems	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**NY or NY/NE**
PowerPlant, STORMS, Business Objects	$500	$500	$0	$0	$0	NY/NE
	Cost ($1000)					
Staff	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**Opex/Capex Split**
Plant Accounting and EDO	$400	$400	$400	$400	$400	50% / 50%
Total	$1400	$1400	$400	$400	$400	50% / 50%

Measures of Success

National Grid will measure its success in the implementation of this recommendation by developing metrics around the number, dollar amount, and time open without charges, and categories and FERC accounts of open work orders. We will establish targets for these metrics and report monthly against the targets. The metrics and targets will be finalized as part of the long term study to be completed by May of 2010.

G. Capital and Operating & Maintenance Budgeting

Recommendation IX-1

Conduct formal reviews of a sample of projects monthly for overall project cost control. The review should include the project manager, system planner, construction supervisor, and appropriate LOB management and include a review of estimates, cost tracking by work break down structure, progress versus cost, and forecast cost.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	David Way, Vice President Project Management and Construction

Background Information

NG plans to conduct formal reviews per the recommendation. Transmission will conduct the reviews at monthly TRAC meetings. Distribution will conduct the reviews at the monthly SRAC meeting.

Presently, the Transmission Portfolio Investment Management business analysts update individual Project Monthly Summary Reports on a routine monthly basis following booking of actual costs and review with the project manager. The report includes a summary of the project status relative to Playbook Steps and full breakdown of project forecasted costs and actual costs to date by spending category referenced in the Sanction Paper. All internal booking of costs and invoices to contractors and suppliers are detailed in the Monthly Summary Report. These Monthly Summary Reports are used to makes changes to project spending forecasts per the Transmission Monthly Investment Management Process outlined in TGP-13.

Changes to project cost forecasts are submitted to the Pre-TRAC meeting and subject to approval at the TRAC meeting.

Distribution businesses present closure papers to the AMIC and DCIG respectively. The closure paper is made for projects $1M or greater and provides the approval committee with final costs, schedule, milestones, significant issues, and lessons learned during the course of the project.

The recommendation does not require new information systems but will be assisted by implementation of Prosight and changes to Primavera. Costs for changes to Prosight for transmission are included below. Costs for upgrades for upgrades to Primavera are included with other Recommendations.

The only new process will be the monthly review of a sample of projects at TRAC. No new staff would be needed for this review.

Asset Management staff will discuss and evaluate the appropriate number of projects to review at monthly TRAC/SRAC meetings. Staff will also discuss how to choose the projects; perhaps from a random selection from the full portfolio of projects regardless of project value, or a random selection within each of several value ranges, with more selected from high value projects.

Proposal to Implement Recommendation

- National Grid began formal reviews of a sample of projects at TRAC and SRAC meetings in December 2009.
- Selected projects for review will be announced at the previous monthly TRAC/SRAC meeting.

- The appropriate business analyst, project manager, planner or asset manager, and construction supervisor will present the status of the project to TRAC/SRAC. The project manager will be responsible for preparing the briefing material and leading the discussion.

- Follow-up actions, if any, will be documented in TRAC/SRAC minutes for tracking and assurance follow-up.

- Significant variances to project schedule or costs will be reported in summary form to AMIC per TGP-11 or at DCIG for distribution projects $1M or greater. Critical projects will continue to be a subject of focus at SRAC.

- TGP-13 will be updated to reflect the required formal review process. TAM staff will discuss and evaluate the appropriate number of projects to review at monthly TRAC meetings. Staff will also discuss how to choose the projects; perhaps from a random selection from the full portfolio of projects regardless of project value, or a random selection within each of several value ranges, with more selected from high value projects. Likewise, Distribution will also determine the appropriate project selection criteria and process. A Distribution Asset Management Guideline will be developed to reflect the process for Distribution.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

National Grid estimates that it will take approximately two months to complete the details of the plan and began on a preliminary basis in December, 2009. In the interim, the

AM and Project Management teams will continue with their work to evaluate and implement the recommendation.

Implementation milestones are summarized in the table below.

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Short Term AM and PM team initiatives	Dec-09	Dec-09	Complete December 31, 2009	Complete~~d~~. Will continue with Capital Investment Group (CIG), Asset Management Investment Committee (AMIC) Transmission Investment Committee (TIC), and Distribution SRAC.
Update process documentation	-	Jun-10	-	In Progress

Summary of Cost/Benefit and Risk Analysis

The distribution, transmission, and shared services costs associated with this recommendation for upgrades to Prosight are $150,000.

Measures of Success

Established procedure that is followed monthly.

Chapter IX – Capital and Operating & Maintenance Budgeting

Recommendation IX-2

Reconcile the differences between planned work identified in the Resource Allocation Committee's reports and expenditures proposed in the January 2009 Transmission and Distribution Capital Investment Plan.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	Pat Hogan, Senior Vice President Distribution Asset Management Paul Renaud, VP Transmission Asset Management

Background Information

The Transmission November 2008 TRAC monthly project file was provided in the DR 209 Supplement. The anticipated 5-year expenditure of $1,681 million in the November TRAC is $155 million higher than the January CIP filing of $1,526 million. Northstar split the November TRAC into "Approved Projects" and "Pending Projects" to develop Exhibit IX-13. Northstar assumed the projects in the NY Forecast list are "Approved Projects" and NY Proposed Placeholders are the "Pending Projects."

This split of the TRAC file is intended primarily to distinguish projects that are pre-strategy approval (NY Proposed Placeholders) versus projects with approved strategies (NY Forecast).

The Distribution difference between the SRAC, provided in the DR 363 Supplement, and the CIP is $41 million.

Proposal to Implement Recommendation

Reconciliation files for Transmission and Distribution to be provided. National Grid plans to engage NorthStar and PSC Staff as part of the implementation plan to help to refine specifics with regards to implementing this recommendation.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

National Grid estimates that it will take approximately two months to complete the details of the plan and begin on a preliminary basis in January. In the interim, the PIM and Project Management teams will continue with their work to evaluate and implement the recommendation.

Implementation milestones are as follows:

Major Activities/Milestones	**Estimated Start Date**	**Estimate Completion Date**	**Actual Completion Date**	**Current Status**
Provide reconciliation files	February 2010	April 2010	Complete May 2010	~~Planned~~Complete, the January 2009 CIP and the November TRAC files have been reconciled and provided. A copy is included as an appendix to this update report.

Summary of Cost/Benefit and Risk Analysis

There are no costs associated with meeting the requirements of this Recommendation.

Measures of Success

The PSC Staff and NorthStar agree the January 2009 CIP and the November TRAC files have been reconciled.

Chapter IX – Capital and Operating & Maintenance Budgeting

Recommendation IX-3

Revise capital investment levels for projects and programs planned as part of the NMPC Transmission and Distribution Capital Investment Plan filed in January 2009 and obtain the necessary commitment for the funds required by NMPC.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	Pat Hogan, Senior Vice President Distribution Asset Management Paul Renaud, VP Transmission Asset Management

Background Information

The Condition of Physical Elements of Transmission and Distribution Systems was filed on October 1, 2009. The report was the basis for the revised Capital Investment Plan filed in January 2010.

The Capital Investment Plan is consistent with the LOB FY11-15 Business Plan submittal. The Business Plan is under review. In keeping with past practice the NG Board will approve a FY11 capital investment budget and approve the outer 4 years of the plan in February or March 2010.

The Capital Investment Plan is consistent with the rate filing submitted to the NY PSC in January, 2010. The outcome of the rate case will demonstrate commitment of National Grid and the NY PSC to the NMPC Capital Investment Plan.

Proposal to Implement Recommendation

The Company has filed a revised Capital Investment Plan on January 29, 2010 which encompasses this review.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Develop Capital Investment Plan	October 2009	January 2010	Complete Jan-10	Completed
File CIP and Rate Case		January 2010	Complete Jan-10	~~Completed~~A revised Transmission and Distribution Capital Investment Plan (CIP) was filed on January 29, 2010. The CIP is consistent with the NY Rate Case filing made on the same date and the NMPC 5-year FY11 to FY15 Business Plan presented to Corporate Finance.
Conclude Rate Case		December 2010		Pending

Summary of Cost/Benefit and Risk Analysis

There are no costs associated with meeting the requirements of this Recommendation.

Measures of Success

The submission of the FY11 5 year Capital Investment Plan on January 29, 2010 was the measure of success for this recommendation.

Chapter IX – Capital and Operating & Maintenance Budgeting

Recommendation IX-4

Set specific target dates and complete the development and execution of Service Level Agreements between the US Transmission and ED&G LOBs and each of the organizational groups and departments that provide shared services to these LOBs as outlined by NG in the collaborative process.

Recommendation IX-5

Amend the service contracts so as to refer to and incorporate as appropriate, the master SLAs and the functional SLAs, which will provide full disclosure about the service levels and costs as well as the types of services provided and the cost methodologies for services provided. (Refers to Finding IX-17)

Recommendation IX-6

Include applicable master and functional SLAs with the annual update of service contracts filed with the PSC. (Refers to Finding IX-17)

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	Jeff Way, Vice President Procurement

Background Information

This is a supplemental recommendation. There are currently 4 centralized service companies within the National Grid USA system, three are legacy KeySpan service companies and one is a legacy National Grid service company. The three legacy KeySpan service companies ("Legacy KeySpan Service Companies") are: (i) National Grid Corporate Services LLC, (ii) National Grid Engineering & Survey Inc., and (iii) National Grid Utility Services LLC. National Grid USA Service Company, Inc. is the legacy National Grid service company. National Grid plans to consolidate three of its four service companies (excluding National Grid Engineering & Survey Inc.) once any necessary regulatory approvals are obtained and these service companies can be unified on a common financial systems platform with common allocation methodologies.

Proposal to Supplement Implementation Plan

The Company has made significant progress to date in furtherance of the SLA model. However, given the importance and scope of this work, the Company believes additional time will be required to carefully consider appropriate approaches to fulfill these recommendations and integrate them into the work plan. The Company's implementation approach will also benefit from the opportunity to consult with Staff. Accordingly, the Company proposes to supplement the Implementation Plan for this recommendation following consultation with Staff.

Update 1 Changes

Revised implementation plan - National Grid has determined based on current circumstances that the number of needed master SLAs to be 31 and the number of functional SLAs to be 71. The number of SLAs required is less than originally anticipated due to consolidation for efficiency. For example Global Procurement was initially anticipating FSLAs for each of their 4 functional disciplines with each of 7 recipients of the FSLA. During FSLA development, these functions were combined into a single FSLA for Global Procurement, reducing the number from 28 (assuming 7 different recipients), to 6 (assuming the consolidation of EDOG and Transmission). All SLAs are expected to be developed and executed by October 2010.

H. Work Management

Recommendation X-1

Complete implementation of improvements to the work management program for field forces as identified in the collaborative process. Improvements include establishing an internal distribution construction workforce, completing the remaining three elements in the EDOT work management initiative, improving its work time standards, and tracking all 29 value metrics for measuring field force productivity.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	John Hoffman, Vice President Strategic Initiatives

Background Information

NMPC has a work management system and utilizes a scheduling tool (i-scheduler) to manage field work. Currently, NG measures estimates against actual and is in the process of refining the estimating tools as referenced in this document.

Staffing levels for internal crews are based on the required crew complement to respond to a 24 hour storm emergency. In a storm emergency the historical evidence has shown that 24 hours is sufficient time to supplement internal crews with external crews. By design, National Grid builds its plan to have internal and contractor crews on property throughout the year.

Proposal to Implement Recommendation

As part of the July 29, 2009 labor agreement extension, a Memorandum of Agreement was established between Niagara Mohawk Power Corp. and IBEW Local Union 97 regarding a “Pilot on Distribution Line Construction (DLC)”. A pilot structure has further been agreed, which outlines the DLC group implementation and measures of success over the pilot duration. The DLC group will construct larger distribution project and program work, consistent with the type of work done by the contracted workforce, and will be measured on the same Key Performance Indicators (KPIs).

Please note that National Grid plans to use the internal distribution construction workforce (DLC - Distribution Line Construction) to perform *distribution construction work.* This model is similar to the Transmission construction model in which the contracted Regional Delivery Ventures (RDVs) are benchmarked against internal transmission construction workforces, specifically the Transmission Line Services (TLS) and Substation Construction Services (SCS) groups.

As described to the NorthStar Auditors, National Grid has identified 29 performance measures. These measures were identified in an unconstrained manner, and although more than 10 have been delivered and are being measured and monitored monthly, the remaining metrics are under design. Where the metrics were defined as 'desired', we are actively reviewing the process and solution modifications and costs to actually deliver on those measures. Based on this assessment, we will decide whether those specific measures are costs effective, or consider new or alternate metrics.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Analyze and design the remaining field productivity metrics	11/01/2009	March 2010	Complete 03/~~01/~~2010	~~In-progress~~Completed review and assessment of the 29 value metrics originally shared through the PSC Management Audit. We have incorporated the effort to further develop the field productivity measures with our overall process oriented performance management framework articulated in our response to IV-1. We are aiming to assess the value of the individual measures against the process oriented performance

				framework and incorporate any T&D Integration work. This will allow us to assess the value of progressing specific measures in the context of our FY10/11 priorities, performance framework and KPI's.
Develop solution and process change requirements and details	01/01/2010	March 2010	Complete April 2010	~~Planned~~Complete
Develop cost and effort estimates to deliver each metrics	02/15/2010	~~March 2010ch 20~~ June 2010		~~Planned~~In progress, to be complete in June
Finalize direction based on costs benefit analysis	03/24/2010	~~April 2010il 20~~ June 2010		~~Planned~~In progress, to be complete in June

Summary of Cost/Benefit and Risk Analysis

The costs to deliver all 29 metrics could be in the range of $500,000 -$1,000,000. This is based on the complexity of delivering the remaining measures and based on the fact we spent $2,000,000 over the past two years to deliver on both the existing KPI's and the performance supervisor scorecards.

The only risk associated with implementing all 29 metrics is whether the costs to actually deliver each measure will provide the key insight and be cost effective.

Measures of Success

Success will be measured by delivering wither all 29 measures or delivering the highest value measures for the right investment.

Chapter X – Work Management

Recommendation X-2

Deliver preliminary annual work plans, especially for mandatory projects, to the construction work forces 90 days prior to the start of the fiscal year so that materials can be ordered and staffing/resource schedules prepared in a timely manner.

Implementation Plan Leads

Executive Sponsor	John Hoffman, VP Operations
Team Lead	Mary Fuller, Director of Program Management Christian Brouillard, Director Investment Management Network Strategy

Background Information

Investment Management, under Transformation, is implementing the Prosite Integrated System Planning (ISP) software tool to improve National Grid's ability to develop and implement its multi-year capital spending plan. The tool will directly interface with Primavera P6 project management system as well as accounting, work order, and estimating systems (also under development). The Company is on schedule to have the ISP tool in place to develop our FY12 - FY16 five-year capital plan.

National Grid has taken steps to accelerate flow of projects from strategies and project identification through to the engineering and design of projects. This will result in a more robust and mature portfolio of projects available for resourcing and scheduling in addition to developing a backlog of schedule-ready work.

National Grid is developing and documenting a process and schedule to guide the flow of work through the steps of strategy, identification, budgeting, resourcing, and approval to occur 6 months ahead of what was delivered in 2009.

The Program Management and Investment Management groups will schedule division operations meetings for January of 2011 to review the details of the FY12 Spending/Resource plan.

Proposal to Implement Recommendation

Continue with development and implementation of US Cost estimating tool, Prosite and Primavera P6.

National Grid estimates that it will take approximately six months to complete the details of the work plan. In the interim, the Investment Management, Program Management and Project Management teams will continue with their work to evaluate and implement the recommendation.

Update 1 Changes

Implementation of Primavera (P6) System Upgrade has been completed for distribution, but anticipated later than initially estimated for transmission for the reasons described in the implementation updates to Recommendation VIII-2, above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimated Completion Date	Actual Completion Date	Current Status
Short Term Asset Management, Program Management and Project Management team initiatives (refine process)		April 2010	April 2010	The time line was developed thru team meetings with Asset Management, Program Management and Project Management. Distribution and Transmission are targeting to have a preliminary view of the FY12 spending plan available to Program Management (PgM) for August 2010 and the draft plan to PgM on October 1, 2010. From these plans, PgM will

				develop the preliminary annual Work Plan for delivery to the construction work forces and stakeholders 90 days prior to the start of FY12. ~~Please see the attached time line chart.~~
System Upgrade (Primavera P6)	-	~~May 2010~~ August 2010	-	The upgrade has occurred for D-Line (March 2010). Requirements for T-Line and Substation are under evaluation. Planned August implementation
System Upgrade (US Cost)	-	June 2010	Complete 03/~~01/~~2010	The intent of the original June 2010 Estimate Completion Date was for the US Cost Application to go live. The full implementation of US Cost was originally scheduled for September 2010 (refer to VIII-4). The US Cost Application is

				live and in use as of 3/30/10. Please refer to VIII-4 for further updates.
System Upgrade (Prosite)	-	June 2010	-	Phased Implementation began in April 2010, NY targeted to go live in June 2010.
Update process documentation	-	~~June 2010~~ September 2010	-	To be completed after systems implementation in Sept 2010

Summary of Cost/Benefit and Risk Analysis

Costs – The distribution, transmission, and shared services costs associated with this NYMA recommendation for development of US Cost, Prosight and Primavera 6 is included in budgeted Transformation costs. Additional training for users of the Prosight tool is estimated to be $70K.

One additional Program Manager for Stations is required for the Stations Work Plan build and implementation, with the cost of $200K.

Measures of Success

The measure of success will be successful development of procedures to implement the recommendation and the successful provision of a preliminary work plan 90 days in advance of the April 1, 2011 for FY2012.

Chapter X – Work Management

Recommendation X-3

Eliminate the remaining in-house tree trimmer positions.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	Chris Root, Senior Vice President T&D Operations and Maintenance.

Background Information

Niagara Mohawk has employed an internal tree trimming workforce since the late 1970's. This workforce was responsible for performing the duties comparable to our current vegetation management contractors. These duties include tree trimming and cutting, tree removal, selective right-of-way clearing, landscaping installation and maintenance, herbicide application and storm response. The internal workforce numbers ranged from a high of approximately 141 internal tree trimmers, in 2001, to the 25 trimmers currently still remaining in the Distribution Forestry Group.

Proposal to Implement Recommendation

Included in the Memorandum of Agreement between Niagara Mohawk Power Corp. and Local Union 97, IBEW Regarding Extension to Labor agreement, ratified on July 29, 2009 a transition plan is in place for the in-house tree trimmers.

- Transition plan facilitates the complete outsourcing of Forestry duties by April 1, 2011.
- Transition plan facilitates placement of employees into available jobs by both geographic and job type preference.
- Employee transition will occur based on a mutually agreeable placement between the Company and the Union.

Schedule

As of 1/7/10, the company has 25 internal tree trimmers remaining in the Distribution Forestry group. In accordance with the agreed MOA, 4 FTEs retired on December 1st. 11 FTEs transitioned to Operational positions on January 4th, 2010. Two FTEs could be placed in Operations in approximately 90 days pending results of the required CAST testing. Of the remaining 23 FTEs, 18 have identified their preference for a position. Depending on availability between now and 3/31/11, they could be placed in these preferred positions if they become available. The last 5 FTEs have elected to stay in Forestry until 3/31/11 at which time they will be placed in accordance with the contract security clause.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above.

As of 4/26/10, the company has 19 internal tree trimmers remaining in the Distribution Forestry group. In accordance with the agreed Memorandum of Agreement (MOA), 4 FTEs retired and 17 FTEs transitioned to Operational positions. Of the remaining 19 FTEs, 13 have identified preferred positions and 5 elected to stay in Forestry until 3/31/2011. Depending on availability between now and 3/31/2011, some of the 13 could be placed in these preferred positions based on availability. The last 5 FTEs will be placed in accordance with the contract security clause on 4/1/2011. Estimated savings are approximately 17%.

Summary of Costs and Benefits

The Company has not completed its analysis of the estimated costs or savings from this recommendation, and will supplement the Implementation Plan as appropriate once completed.

Costs and Benefits Update 1

The analysis is performed at the crew level with labor and equipment rates standardized to reflect the optimized crew compliment as needed to perform the duties required of the Vegetation Management Program for both the internal workforce and contract workforce. (All rates are fully loaded).

Contractor

	Rate/hr
a) "A" Forman	$41.68
b) Journeyman trimmer	$37.48
c) 55' Aerial Lift	$12.75
d) Chipper - self disk	$3.98
	$95.89

Internal

	Rate/hr
a) Chief Tree Trimmer A	$51.84
b) Tree Trimmer C	$47.57
c) 55' Aerial Lift	$11.25
d) Chipper - self disk	$4.38
	$115.04

Cost savings Estimate by Outsourcing - 17%

Measures of Success

Not applicable.

Chapter X – Work Management

Recommendation X-4

Separate the EDOT project into elements and evaluate them as individual projects in the business planning process, rather than treating them as an on-going mega project. At a minimum, integrate the current EDOT into the business planning and performance management process.

Implementation Plan Leads

Executive Sponsor	Ellen Smith, Chief Operating Officer
Team Lead	John Hoffman, Vice President Strategic Initiatives

Background Information

The auditor made the following observations in relation to this recommendation.

X-18 - The EDOT program operates independently of the regular business planning and capital and O&M budgeting process.

- While the development of the EDOT was in response to and independent from the FY08-09 planning process, NG could have segmented the activities of the EDOT project into individual projects and aligned them with strategies and activities of the appropriate operating groups in the FY09-10 business plan.
- The projected cost/efficiency savings were embedded in operating budgets for FY09-10 and beyond, without the "owning" managers fully knowing what tools would be available to meet the efficiency targets.
- The existence of the EDOT as a stand-alone project outside the FY09-10 business plan makes it difficult to determine whether its activities are in alignment with the overall plan and its elements.
- EDOT includes cross-LOB and support and shared services coordination and the program and project management discipline to performance improvement initiatives that are lacking in the regular financial and operations planning and performance management processes and the functional governance group process.
- EDOT preceded and is now operating in parallel to NG's Global Transformation Program which could potentially result in realignments that make the EDOT initiatives irrelevant or counterproductive. The Global Transformation program encompasses a range of initiatives that include:
  - Global procurement.

- A global Enterprise Resource Planning (ERP) systems solution for front office, back office and customer systems.

- Global shared service activities.

Proposal to Implement Recommendation

Going forward business planning will continue to integrate the EDOT benefits into the business planning process.

- Sustainable management of EDOT benefits to be integrated into the EDO&G's Performance Management process.

- Hold monthly EDOT Value Case meetings with the team sponsors and business owners in order to monitor progress of the initiatives and benefits achieved.

- Hold monthly EDOT Steering Committee Meetings to keep the business owners informed of the progress of the systems, processes, and procedures being implemented by EDOT.

- Prepare weekly progress reports so business owners are aware of the status of the capabilities, systems and tools being implemented in EDOT.

- Maintain a program level work plan and individual work plans for each of the individual projects within transformation.

- Maintain the EDOT business case in order to track the progress of the individual projects by business owner.

Note: The EDOT initiatives have been done in coordination with the original global transformation program to ensure that the initiatives do not become irrelevant or counterproductive. The global initiatives will serve to build on the work of EDOT.

Update 1 Changes

Updated team lead and executive sponsor information is reflected above.

Schedule

Implementation milestones are summarized in the table below.

Milestone	Expected Completion
Align Transformation with Performance Management (organizationally)	Complete
Align Transformation with Business Planning Process	Complete

Summary of Cost/Benefit and Risk Analysis

There were no incremental costs associated with the proposed changes.

Measures of Success

The ability to see and manage transformation related activities and value will be assigned to owning managers and tracked within individual budgets. Managers will be versed in the commitments.

Chapter X – Work Management

Recommendation X-5

Review the practicality of the new storm response plans to ensure that NMPC ratepayers will be provided with timely and qualified services in the event of a storm emergency.

Implementation Plan Leads

Executive Sponsor	~~John Hoffman, Vice President Operations~~Neil Proudman, Vice President Transmission & Distribution Services
Team Lead	Robert Kearns, Director Emergency Planning

Background Information

National Grid's legacy companies historically maintained electric system restoration plans ("storm plans"), governing each company's response to a major restoration event. The operational integration of these legacy companies has resulted in the availability of significantly greater quantities of line and forestry crews available for rapid deployment to impacted portions of National Grid's overall service territory, directly benefitting customers. While the consolidation of clerical and design resources offers consistency and increased efficiency both on a day-to-day basis and during storms, these groups may also be rapidly deployed to impacted portions of National Grid's service territory, to assist in the restoration process.

Proposal to Implement Recommendation

National Grid's Transformation initiative includes provisions for the effective management of storms, post-centralization of clerical and design staff. Associated enhancements to National Grid's storm plans are scrutinized by representatives of Emergency Planning and Operations, prior to implementation. Specific aspects of the plans, relating to the centralization of resources are tested during drills and via actual deployment during minor weather disturbances, to ensure they are effective. The National Grid's storm plans are also updated and tested on an annual basis. These updates and tests ensure that issues are identified prior to actual storm emergencies and any required improvements are implemented.

Certain storm response functions will be centralized and conducted remotely, post-Transformation. A clerical pool, based in Syracuse, NY, will conduct a variety of logistics functions, as well as time entry and miscellaneous data entry tasks for the entire Upstate NY region. A quantity of clerical and design workers will remain within each division and will continue to perform certain storm response functions locally. Additional resources who will remain within each division (I.e. Design Investigators and Supervisors) will be trained and will supplement in performing "storm board" (crew dispatching) functions. Still others who will remain (I.e. Distribution Inspectors, Meter & Test Personnel, Relay Technicians, Communication Technicians and Contractors), will assist in performing Damage Appraisal functions.

As referenced above, logistics functions will be centralized in Syracuse, for the entire Upstate NY region. Other functions as mentioned in the PSC Audit Report will be handled as follows:

Running lunches to crews: Logistics plans includes distributing boxed lunches to line and forestry crew members at the start of each day, from their hotel or staging site. In limited cases, where this service is not provided, crew leaders or supervisors may travel to a designated distribution point to retrieve lunches for crew members. In other limited cases, National Grid Gas Distribution or Meter personnel will be called upon to deliver lunches to crew work locations.

Distributing maps, contractor packages and other logistical materials: Remaining personnel who traditionally perform these "storm board" functions, as described above, will be supplemented by Design Investigators and Supervisors, in each division.

Pre-check in of crews at night: This function is no longer performed. Centralized logistics teams will assign hotel rooms. Crew members, leaders and supervisors will continue to check in independently at designated hotels and register as hotel guests.

Preparing documentation, including timesheets: This will be performed remotely, via the central clerical team located in Syracuse, NY.

Post-Transformation storm response procedures will significantly limit the need for centralized clerical staff to travel to remote areas. In most cases, functions which can be performed remotely (via Syracuse) will be. Additional resources have been identified in the remote divisions, to supplement personnel who will conduct storm response functions locally (see first bullet, above). In rare cases, employees who are normally assigned to Syracuse may be requested to travel to a remote division, either to supplement the local response or to provide relief for existing employees – several days into a long-term restoration event. It is anticipated that the majority of these employees will be able to travel to their intended destinations, as would be the case for foreign (mutual aid) crews, material supplier vendor vehicles, fuel delivery vehicles and municipal emergency response vehicles, etc.

National Grid's logistics plan is robust and highly scalable. Contractual agreements are in place with numerous local, regional and national vendors to supply lodging, vehicles, meals, laundry services, etc. In addition, Base Logistics (a national logistics management vendor) has been retained to coordinate the setup, management and demobilization of "staging sites" which can be established throughout all of National Grid's service territory. Utility companies, as well as fire services and other emergency response agencies have historically relied upon the "mutual aid" process to supplement the response to a major emergency. Logistics plans are designed to be scalable, to ensure all supplemental workers called into an area, in response to an emergency, can be lodged, fed and generally cared for. This includes any internal personnel who may assist in a neighboring portion of National Grid's service territory.

Update 1 Changes

Updated executive sponsor information is reflected above. Schedule and progress updates appear below.

Schedule

Major Activities/Milestones	Estimated Start Date	Estimate Completion Date	Actual Completion Date	Current Status
Identify and train centralized clerical staff to deploy to remote "impacted" areas to perform "storm board" functions.	-	Complete	Complete	-
Identify and train Design Investigators and Supervisors remaining in the divisions to perform "storm board" functions	-	March 1, 2010	Complete 03/2010	Network Strategy designers and T&D Services employees have been assigned to new storm roles and have been trained. Designers supplement operations supervisors in overseeing the response of line crews during storms. T&D Services' employees assist in operating the Outage Management System (PowerOn/PORD) and provide general office support. As personnel were trained, the Storm Emergency

				Assignment Listing (SEAL) database was updated to reflect revised assignments and training dates.1. T&D Services' employees were rapidly and successfully deployed to NY-Central remote divisions, in response to a snow storm in December, 2009. 2. Designers were successfully deployed to Long Island, NY in March, 2010, to assist in supervising line crews in response to a major rain and wind storm.

Summary of Cost/Benefit and Risk Analysis

There are no incremental costs associated with the proposed changes.

Measures of Success

Demonstrated response of Design Investigators, Supervisors and centralized Clerical Staff to perform "storm board" functions in future storms. (Note: Centralized Clerical staff were rapidly and successfully deployed to NY-Central remote divisions, in response to a snow storm in December, 2009)

APPENDIX

Recommendation IX-2

Reconciliation of

January 2009 CIP and November TRAC

BUDGET RECONCILIATION - CIP VS SRAC

NorthStar Exhibit:

Exhibit IX-14
Proposed Distribution Investment vs. SRAC totals
($ millions)

Source	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14
January 2009 Filing	$239	$270	$294	$309	$327
SRAC	244	277	292	324	343

Source: DRs 213 and 363 Supplement

	DISTRIBUTION 2009/10		DISTRIBUTION 2010/11	DISTRIBUTION 2011/12	DISTRIBUTION 2012/13	DISTRIBUTION 2013/14
January 2009 Submission - CIP Document	**239,353,000**		**269,700,000**	**294,000,000**	**308,700,000**	**326,500,000**
Internal Adjustment of out-year inflationary assumptions	-		(1,100,000)	(2,700,000)	(4,400,000)	(6,000,000)
PENSION ADJUSTMENT (Non-Adjustment)	13,680,000	(1)	15,800,000	17,980,000	20,145,000	22,427,000
Deferral of Capital Project through prioritization process/Capital Investment Process	(8,864,000)	(2)	(7,000,000)	(17,000,000)	0	0
Final SRAC BUDGET/FORECAST	**244,169,000**		**277,400,000**	**292,280,000**	**324,445,000**	**342,927,000**

(1)

The Pension Adjustment of the budget was applied evenly to all budgeted projects except for the largest material only projects - transformer & meter purchase blankets. The adjustment was calculated as a percentage of the budget less those large purchase projects and each line item was increased by the corresponding percentage which worked out to be 6.5%. This methodology was used as the initial budget estimates do not include a breakout whether of internal or external labor will be used for a given project.

January Submission Budget- FY09/10	**$239.4** m	
Less: Large Projects with no labor:		
Transformer Purchase Blank	$23.9 m	
Meter Purchase Blanket	$4.7 m	
Adjusted Budget dollars	**$210.8** m	(a)
Dist Pension Adjustment	$13.7 m	(b)
% to increase each project	6.5%	(b)/(a)

(2) The Plan adjustment of -$8.864m was a combination of project cuts, project reductions, scaling back of programs and additions of other capital projects which now warranted inclusion of capital dollars in the Fy10 budget. The full list of these items is included in the worksheet "April 2009 Changes". Also included in the worksheet is whether that Capital Project # is included in the current FY11-FY14 capital plan.

BUDGET RECONCILIATION - CIP VS TRAC

	Transmission 2009/10		Transmission 2010/11	Transmission 2011/12	Transmission 2012/13	Transmission 2013/14	
January 2009 Submission - CIP Document	**120,609,000**		**219,639,856**	**359,391,665**	**452,280,191**	**373,512,073**	
Additional Capital Projects through prioritization process/Capital Investment Process	5,000,000		34,770,000	43,420,000	67,210,000	4,130,000	**(1)**
Final TRAC BUDGET/FORECAST	**125,609,000**		**254,409,856**	**402,811,665**	**519,490,191**	**377,642,073**	

(1) The Plan adjustments +$155m over the course of 5 years was a combination of project re-phasing, scaling back of programs and additions of other capital projects which now warranted inclusion of capital dollars in the Business Plan. The full list of these items is included in the worksheet "Tx April 2009 Changes".

(8,864,000)
TOTAL ADJUSTMENT

Proj #	Project Description	Original FY10 Budget $557M	Adjustments	Final $527M Budget
C00469	Wilton - Install 34.5kV Circuit Brk	200,000	(200,000)	-
C00475	Seneca Terminal Sta Repl 23 kV Bkr	150,000	(150,000)	-
C00476	Kensington Terminal Station - Rpl 2	150,000	(150,000)	-
C00498	Western Rgn Stations - McG Ed 38kV,	300,000	(300,000)	-
C04338	Spares	1,494,000	(1,394,000)	100,000
C06375	Bremen-Automate 115kV Switches	80,000	(80,000)	-
C06379	NR-Lowville-Automate 115kV switch	797,000	(797,000)	-
C15658	Sawyer Sta - Add Cable Positions	500,000	(150,000)	350,000
C23353	Install Animal Fences & Line Guards	249,000	(149,000)	100,000
C25321	NY Mobile Station Readiness Program	448,000	(448,000)	-
C25324	NY Asset Replacement Conceptual	151,000	(126,000)	25,000
C25811	NY ARP Batts/Chargers Repl Prog	398,000	(20,000)	378,000
C25999	NY ARP FOR TXD SUBSTATIONS	500,000	(200,000)	300,000
C26050	NY ARP Caps & Switches	249,000	(199,000)	50,000
C26561	S.Livingston-115-13.2KV- Bus & Bkr	1,494,000	(1,294,000)	200,000
C28124	Replace Schuyler 210 breaker	1,425,000	(1,425,000)	-
C28146	Seneca Reactors Purchase	1,611,000	(1,111,000)	500,000
C28876	Butler Sub - Add 3rd Breaker, R530	299,000	(299,000)	-
C29026	North Collins - Replace TB1	498,000	(498,000)	-
C29027	North Eden - Replace TB1	597,000	(597,000)	-
C29028	South Newfane 71 - Replace TB1	498,000	(498,000)	-
C29048	Town of Elberta - DC in a box	398,000	(398,000)	-
C17991	NW HUF Relief	100,000	(100,000)	-
C26222	Buffalo State UG 23 kv	400,000	(399,000)	1,000
C26818	Town of Elberta - DC in a box	398,000	(398,000)	-
C28106	Swann Rd F10552 tie with F10557	299,000	(299,000)	-
C28724	Lakeview 18251 - 18254 Feeder Tie	146,000	(146,000)	-
C28725	Cloverbank 9153 -Lakeview 18254 Tie	108,000	(108,000)	-
C28887	Station 43 - Load Relief	115,000	(115,000)	-
C28890	Buffalo 23kV Reconductor - Seneca	250,000	(225,000)	25,000
C28899	Farmersville bank relief	5,000	(5,000)	-
C29045	Whitehaven Rd 64 - F6454 Relief	199,000	(199,000)	-
C29047	Wilson Sta 93 - Load Relief	996,000	(996,000)	-
C29185	23kV Cable Replacement Program	2,879,000	(160,000)	2,719,000
C07469	Whitehall 18752 - Rebuild Route 4 o	398,000	(398,000)	-
C14063	IE - NE Targeted Pole Replace	1,494,000	(403,000)	1,091,000
C16085	Quail Hollow - new 13.2kV feeders	50,000	(50,000)	-
C17992	NE HUF Relief	100,000	(100,000)	-
C25400	PIN 1248.14 State Route 149 DOT	498,000	(498,000)	-
C28766	Wolf Rd 34453 - add feeder tie	203,000	(203,000)	-
C28786	Liberty 9490 - replace getaway	121,000	(121,000)	-
C28790	Alps - new dist sub - D Line work	200,000	(150,000)	50,000
C28845	Queensbury 29557 Exten. Bay St.	30,000	(30,000)	-
C28875	Queensbury 29552 Exten Aviation Rd	20,000	(20,000)	-
C28878	Butler - Construct Feeder 36253	299,000	(299,000)	-
C29110	Colvin 31387 Getaway cable repl	278,000	(278,000)	-
C29111	Cobleskill 21412 Getaway cable repl	62,000	(62,000)	-
C00253	Hinsdale Fdr Relief	224,000	(224,000)	-
C08918	IE - NC Targeted Pole Replace	1,494,000	(803,000)	691,000
C08999	Erie Blvd 13.2kV - New Rome 76252	125,000	(125,000)	-

C17990	NC HUF Relief	100,000	(100,000)	-
C26776	Yahnundasis 64656 Reconductor Rte 5	209,000	(141,000)	68,000
C26816	Carthage-High Falls#21	500,000	(499,000)	1,000
C26922	NR-N Gouvernuer 98352-CoRt 10	203,000	(203,000)	-
C26971	NR-Heuvelton 92372_McAdoo 92451	325,000	(325,000)	-
C27682	Fort Covington sub-T work TxD	90,000	(90,000)	-
C28027	NR 89865 Bilow Farm	16,000	(16,000)	-
C28065	Union-L. Clear 35 Bloomindale tap	66,000	(66,000)	-
C28289	Lehigh 66953 tie with LHH 6144	50,000	(50,000)	-
C28344	CNY Network Protector Replacement	279,000	(68,000)	211,000
C28587	Southwood 52 Reconductor	374,000	(374,000)	-
C28589	Southwood 51 Reconductor	413,000	(413,000)	-
C28605	Jewett Rd 56 correct low voltage	547,000	(547,000)	-
C28827	NR-David 97967 Jay St Exten.	199,000	(199,000)	-
C28829	MV-Alder Creek Dustin Rd Ext./Conv.	897,000	(897,000)	-
C28850	Tinker Tavern Step Down	348,000	(348,000)	-
C28855	Conkling Relief	154,000	(154,000)	-
C16655	Mainline Recondutoring	2,241,000	(2,241,000)	-
CTASK0815	TASK - Sub-T Line NYE Co 36	-	(351,000)	(351,000)
CTASK0816	TASK - Sub-T NYE Co 36	(200,000)	(839,000)	(1,039,000)
CTASK0817	TASK - Sub-T Line NYC Co 36	-	(351,000)	(351,000)
CTASK0818	TASK - Sub-T NYC Co 36	(200,000)	(838,000)	(1,038,000)
CTASK0819	TASK - Sub-T Line NYW Co 36	-	(351,000)	(351,000)
CTASK0820	TASK - Sub-T NYW Co 36	(200,000)	(838,000)	(1,038,000)
CTASK0921	TASK - IE Line	996,000	(935,000)	61,000
CTASK0925	TASK - D-Line NC Co 36	398,000	(150,000)	248,000
CTASK0929	TASK - D-Line NE Co 36	398,000	(299,000)	99,000
CTASK0932	TASK - D-Line NW Co 36	398,000	(299,000)	99,000
DBBPROG20	IE - UG Structures & Equip. - NY Placeholde	2,241,000	(1,541,000)	700,000
DBBPROG22	IE - Pockets of Poor Performance - NY Place	597,000	(597,000)	-
DBBPROG24	IE - UG Cable Replacement - NY Placeholde	748,000	(702,000)	46,000
C08153	PS&I Activity - New York	398,000	(298,000)	100,000
C15660	Homer Hill Sta - Rep Cap Bank & Bkr	500,000	(300,000)	200,000
C15669	Cuba 05 - Replace Transformer Bank	398,000	(358,000)	40,000
C19851	REP SCADA (EMS Expansion)	748,000	(748,000)	-
C20173	REP - Dist Subs Requiring RTUs	149,000	(149,000)	-
C25801	IE - NY ARP Transformers	1,593,000	(753,000)	840,000
C26054	NY ARP MetalClad Equipment	2,490,000	(1,490,000)	1,000,000
C28770	Inman Rd -add M/C & 13.2kV Bus work	2,987,000	(2,687,000)	300,000
C28931	Frankhauser-115-13.2KV- Bus & Bkrs	597,000	(497,000)	100,000
C29049	Younsgtown 88 - Station Rebuild	398,000	(398,000)	-
C10967	IE - NW Dist Transformer Upgrades	597,000	(136,000)	461,000
C17668	L630 & 631 Hendrix Ca + LBSwitches	500,000	(450,000)	50,000
C27562	208 line refurbishment	800,000	(600,000)	200,000
C27563	305 line refurbishment	1,000,000	(950,000)	50,000
C27949	Buffalo Station 52 Rebuild - Fdrs	747,000	(100,000)	647,000
C28606	F5769/5763 Rebuild r/o Floradale	228,000	(228,000)	-
C28625	F20871 rebuild ties F4768/F2569	137,000	(137,000)	-
C28652	Delameter F9352 new ties w/18251,53	478,000	(478,000)	-
C28689	F9753 Rebuild/Conv tie w/F21754	389,000	(389,000)	-
C28717	N.Leroy 0455 - Mumford 5052 Fdr Tie	444,000	(444,000)	-
C28718	E.Batavia 2855 - N.Leroy 0456 Tie	484,000	(484,000)	-
C28719	Batavia 0155 - Knapp Rd 22651 Tie	592,000	(592,000)	-
C28726	Sweet Home F22457 tie with F2165	267,000	(267,000)	-
C28892	Buffalo 23kV Reconductor - Huntley	960,000	(930,000)	30,000
C28893	Buffalo 23kV Reconductor - Huntley2	1,168,000	(1,118,000)	50,000

C28894	Buffalo 23kV Reconductor - Kensing.	544,000	(519,000)	25,000
C28903	Buffalo 23kV Reconductor - Kens2	117,000	(88,000)	29,000
C28929	Frankhauser New Station - Line Work	309,000	(270,000)	39,000
C06739	Charlton-Ballston #9 Rebuild/Recnfg	500,000	(450,000)	50,000
C07438	Chestertown 52 - Duell Hill Rd.	199,000	(199,000)	-
C07519	Rebuild Greenbus-Defrevle 7	200,000	(200,000)	-
C08606	Delmar 440, Jun, Vooh 52 Conversion	448,000	(17,000)	431,000
C13146	FH - NE Feeder Hardening	2,340,000	(1,222,000)	1,118,000
C13266	IE - NE Recloser Installations	2,656,000	(24,000)	2,632,000
C15828	IE - NE Dist Transformer Upgrades	597,000	(147,000)	450,000
C16073	Newtonville-Patroon #16 Refurb	550,000	(500,000)	50,000
C16236	Gloversville - Canaj. #6 Refurbish	1,500,000	(1,450,000)	50,000
C18991	Port Henry 51 - Convert Westport	348,000	(348,000)	-
C27564	Battenkill-Cambridge 34.5kv Refurbi	250,000	(100,000)	150,000
C27583	Spier-Glens Falls 8-pls	500,000	(450,000)	50,000
C28018	Market Hill-Amsterdam 11,Tap Mohasc	437,000	(377,000)	60,000
C28022	Sycaway-add new feeders	558,000	(408,000)	150,000
C28023	Reynolds Rd - add new feeders	698,000	(623,000)	75,000
C28765	Johnson 35251 - getaway replacement	84,000	(84,000)	-
C28772	Inman Rd - add new feeders	263,000	(223,000)	40,000
C28780	Seminole 33904 - add feeder tie	115,000	(115,000)	-
C28781	Riverside 28854 - replace getaway	101,000	(101,000)	-
C28844	Brook Rd 36957 Exten. Adams Road	498,000	(448,000)	50,000
C29113	Brook Road 36954 Getaway cable repl	607,000	(300,000)	307,000
C29434	Middleburg 51 - Tie to Schoharie	169,000	(169,000)	-
C29438	Scofield Rd 53 - Tie to Corinth 51	698,000	(555,000)	143,000
C13145	FH - NC Feeder Hardening	2,340,000	(1,222,000)	1,118,000
C13267	IE - NC Recloser Installations	2,656,000	(186,000)	2,470,000
C14846	IE - NC Dist Transformer Upgrades	597,000	(147,000)	450,000
C22959	NR-W.Adams87554-Church St	39,000	(39,000)	-
C26973	NR-State St 95463-Judson St Rebuild	166,000	(80,000)	86,000
C26977	Doghouse Replacement - Central Div	498,000	(448,000)	50,000
C28017	Trenton-Deerfield 21/27-46kv	500,000	(450,000)	50,000
C28607	Lehigh 66952 Tie With Colosse 32151	398,000	(398,000)	-
C28610	Peterboro Reconductor Main St.	175,000	(175,000)	-
C28616	Walesville Reconductor Utica St	61,000	(55,000)	6,000
C28617	Lehigh 66954 Teelin Rd Relocate	179,000	(179,000)	-
C28771	Trenton Whitesboro 25 Reconductor	1,260,000	(1,210,000)	50,000
C28816	Chittenango Relief	299,000	(100,000)	199,000
C28820	Park Load Relief	164,000	(124,000)	40,000
C28832	Bartell 56 Orangeport	199,000	(199,000)	-
C28848	Mexico Load Relief	339,000	(150,000)	189,000
C28849	Phoenix Load Relief	279,000	(279,000)	-
C28852	Starr 53 Step Down	253,000	(100,000)	153,000
C29101	NR-N Gouverneur 98352-Rt58 Transfer	50,000	(50,000)	-
C29742	DOTR I-81 bridge reconstruction Syr	187,000	(187,000)	-
C26839	Mercury Vapor Replacement	1,992,000	(1,242,000)	750,000
C00279	NR-Bloomingdale-Replace Sta Struct	-	723,000	723,000
C06360	Whitesboro R260-R290 replacement	-	10,000	10,000
C06368	NR-Westville - TB#1,Fuses, & Bkr	-	627,000	627,000
C06533	East Golah 51 - Second Bank	-	1,500,000	1,500,000
C15791	York Cen Sta 53 - New 115/13.2 TB	-	50,000	50,000
C15805	E Batavia - Repl TB1 & TB2	-	1,469,000	1,469,000
C18595	DxT Substation Dmg/Fail Reserve C36	149,000	101,000	250,000
C20174	TxD Mobile Substations in NY	1,300,000	700,000	2,000,000
C20211	Mobile Sub 5W Rewind	-	452,000	452,000

C22151	NY RTU Program - DxT Subs	-	550,000	550,000
C24066	LTC Filtration Systems NY DxT FY09	-	150,000	150,000
C24240	Battery Strategy FY09 CO36 DxT	-	250,000	250,000
C24419	Replace Metal Clad at Springfield	-	800,000	800,000
C24559	Animal fences for NYED Substations	-	100,000	100,000
C25139	Replace/Relocate 13.8kV SG @Oneida	750,000	1,550,000	2,300,000
C25262	Chestertown replace SW688 w/ brkr	-	200,000	200,000
C25559	Southwood - Inst. Mobile Sub Access	30,000	10,000	40,000
C25599	NY ARP Breakers & Reclosers	-	1,300,000	1,300,000
C25639	Buffalo Indoor Sub. #23 Refurb.	2,358,000	1,570,000	3,928,000
C25659	Buffalo Indoor Sub. #52 Refurb.	2,551,000	236,000	2,787,000
C25660	Buffalo Indoor Sub. #43 Refurb.	1,738,000	1,600,000	3,338,000
C25684	NY ARP Spare Breaker & Recloser	-	100,000	100,000
C26418	Sycaway - Add M/C and 13.2kV Bus	747,000	3,000	750,000
C26419	Reynolds - Add M/C & Equip	-	2,200,000	2,200,000
C26481	S. Newfane 71 - Replace Bank	100,000	550,000	650,000
C26760	NY Small Capital Items	100,000	150,000	250,000
C26879	Stoner - Install 4th Breaker R540	-	275,000	275,000
C27323	NR- Morristown 2.5 MVA	299,000	245,000	544,000
C27449	Swann Rd TB2 Replacement	1,245,000	850,000	2,095,000
C28126	NY PCB Bushing Spill Containment	-	141,000	141,000
C28485	North Troy Metal Clad Repl.	750,000	1,750,000	2,500,000
C28788	Alps - new dist sub - add feeder	-	100,000	100,000
C28838	Clinton St Cooling/3rd Feeder Canaj	-	40,000	40,000
C29209	Elm 23kV Shunt Reactor	-	160,000	160,000
C29741	Liberty Str. Sub - Control Building	-	150,000	150,000
C00492	Youngstown - Mountain #401 Line	350,000	525,000	875,000
C06724	Buffalo Station 29 Rebuild - 23 kV	250,000	246,000	496,000
C06820	Line 218 - Reconductor	-	200,000	200,000
C13268	IE - NW Recloser Installations	2,656,000	4,000	2,660,000
C13282	IE - NW Cable Replacements	-	800,000	800,000
C14951	DOT Reloc Conduit Babcock St	-	100,000	100,000
C15081	City/DOT Babcock St-23kV Cables	-	206,000	206,000
C15667	Regulators 34.5kV on Line 208 & 225	-	350,000	350,000
C15724	NYSDOT Ridge Rd Bridge	-	170,000	170,000
C16119	IE - NW ERR and Fuse	-	325,000	325,000
C25940	Batavia-Attica 206-34.5kv	-	100,000	100,000
C26379	Attica12-Rebuild,Xfer F1263 to 0158	-	1,300,000	1,300,000
C26396	DOT-Main St Buffalo Road Work	-	300,000	300,000
C26406	F2471-Reconductor Mang Ave	-	100,000	100,000
C26476	Mumford 5051 Tie with E. Golah 5155	-	660,000	660,000
C26557	F13861 Extend & Transfer to F23251	-	300,000	300,000
C26558	F13862 Extend & transfer to F23255	-	100,000	100,000
C26559	F7654 - Extend & Transfer to 23251	-	500,000	500,000
C26639	Seneca Niagara Casino Relocation NF	-	400,000	400,000
C26696	F20655 - Hendrix Cable Installation	249,000	446,000	695,000
C26841	Heltz Rd. Conversion to 13.2 KV	-	260,000	260,000
C27062	East Golah 51 - Secondary Breakers	-	1,000,000	1,000,000
C27438	Oakfield-Caledonia 201-34.5kv Rbld.	-	200,000	200,000
C27505	856 line refurbish	250,000	300,000	550,000
C27946	Buffalo Station 52 Rebuild - 23 kV	250,000	12,000	262,000
C28012	F13862 reliability improvement	190,000	25,000	215,000
C28085	Darien F1662 feeder tie	268,000	50,000	318,000
C28715	W.Hamlin 8254 - Tie w/F8252 & F7458	556,000	110,000	666,000
C28722	New Langford 18061 - New Regulators	36,000	4,000	40,000
C28841	Station 97 - New F9755	448,000	92,000	540,000

C28846	Station 61 - Relief	149,000	30,000	179,000
C28943	NYDOT_Wherle Drive	-	100,000	100,000
C29040	Byron Station Load Relief	712,000	157,000	869,000
C29044	Long Road 209 - New FDR 20954	597,000	113,000	710,000
C29485	Relocate and tap Line 856 to ECWA	-	113,000	113,000
C30685	Wal-Mart Sheridan Dr. - New Service	-	496,000	496,000
C31067	DYOUVILLE COLLEGE New 23 KV Service	-	276,000	276,000
C31297	New Walmart Leroy Project	-	78,000	78,000
C31340	REBUILD 2361 FOR NEW WALMART	-	94,000	94,000
CNW021	West NY-Dist-Telecomm Blanket	-	8,000	8,000
C06679	Boyntonville 51 Regulators	-	150,000	150,000
C07238	Capitalizeable B-Maintenance	-	50,000	50,000
C07431	Watt 32052 - Conversion	-	435,000	435,000
C07477	Northville 52 - Convert N. Shore Rd	-	132,000	132,000
C07482	Battenkill 34257 - Rebuild/convert	-	80,000	80,000
C10164	Schuylerville 12- Reconductor Rt 29	-	200,000	200,000
C11099	IE - NE Cable Replacements	-	500,000	500,000
C11818	McClellan-Bevis #11 34.5kV Prel Eng	500,000	500,000	1,000,000
C16070	Rott - Schoharie #18 refurbishment	-	350,000	350,000
C16072	Maplewood-Latham #9 Refurb	50,000	1,150,000	1,200,000
C16078	Maplewood-Lib 2/13 repl cable	-	52,000	52,000
C16079	Riv-Part #9 and #37 repl cable	800,000	310,000	1,110,000
C16117	IE - NE ERR and Fuse	-	450,000	450,000
C16234	Vischer - Woodlawn #3 refurbish	-	750,000	750,000
C16237	Gloversville-Hill St #3 Refurbish	-	800,000	800,000
C16451	Farnan Rd 51 - Woodscape Phs 2 URD	-	50,000	50,000
C19272	Caroga - G'ville 53 Feeder Tie	597,000	759,000	1,356,000
C20351	St. Peter's Hospital Taps	-	151,000	151,000
C20691	Selkirk - Bethlehem Tie	-	50,000	50,000
C22224	LFTC POD 10 URD	-	10,000	10,000
C24233	Primary service for Taconic Farms	-	350,000	350,000
C25099	Park Place @ Malta, Ph I	-	150,000	150,000
C26636	Greenbush-Rensselaer#10&#11 Rebuild	500,000	36,000	536,000
C26797	Battenkill-Cm Mt #5: Thompson Tap	-	10,000	10,000
C26876	Corinth 52 - Eastern Ave. Rebuild	-	60,000	60,000
C26877	Guy Park Retirement Dist. Line	-	250,000	250,000
C26878	Stoner 35854 Getaway	24,000	38,000	62,000
C26902	Lape - Snyders Lake Tie	-	255,000	255,000
C27729	DOTNR-PIN # 1248.14- NY-Eastern Div	398,000	52,000	450,000
C27857	V-344	159,000	19,000	178,000
C28288	Canajoharie 03124 Clinton Rd	-	255,000	255,000
C28447	Rotterdam-Schoharie #18 Middleburg	-	400,000	400,000
C28524	V-16 James & State St Roof Replace	160,000	15,000	175,000
C28527	V-66 James St Roof Replacement	157,000	20,000	177,000
C28791	Krumkill 51 Russell Rd convert	374,000	1,000	375,000
C28825	Krumkill Voorheesville Tie	60,000	190,000	250,000
C28843	Church St 04358 exten.	199,000	141,000	340,000
C29452	Crescent -School St/N. Troy 17/20	-	100,000	100,000
C29988	Church St 04351 Ductbank	-	154,000	154,000
C30024	City of Albany - Delaware Ave	-	120,000	120,000
C30405	Extend 3 phase for Widewaters Proj	-	100,000	100,000
C30825	372 Battenkill Bridge - DOT	-	145,000	145,000
C31318	DOT Albany, Fuller Rd.		323,000	323,000
C31385	DOT Colonie, Maxwell Rd.		135,000	135,000
C31543	DOT Amsterdam, Bridge St.		350,000	350,000
C31602	Bolton 52 - Convert Valley Woods Rd		200,000	200,000

CNE021	East NY-Dist-Telecomm Blanket	-	8,000	8,000
C00194	NR-Distr-8043.08-CuNapth(soleowned)	-	538,000	538,000
C00413	Schuyler-Valley 21/24	150,000	600,000	750,000
C06894	Seneca Hill Rebuild Rt 48	-	525,000	525,000
C07804	Rathbun-Labrador #39 Rebuild	50,000	1,450,000	1,500,000
C07810	Colony-Browns Falls #21 Rebuild	-	250,000	250,000
C07813	Emeryville-Mine Rd #23 Rbld & SWS	-	742,000	742,000
C07814	Lowville-Boonville #22 Rebuild	200,000	600,000	800,000
C09354	NR-Westville-TB#1(Fdr Rework)	100,000	55,000	155,000
C12058	Piercefield-Tupper Lake #39 Rebuild	200,000	250,000	450,000
C13046	Lake Clear-Tupper Lake #38 Rebuild	420,000	280,000	700,000
C13822	IE - NC Cable Replacements	-	150,000	150,000
C14626	NR-Paul Smiths 83462 Line Upgrade	149,000	25,000	174,000
C14909	CR Rebuild New Haven Rt 3	-	554,000	554,000
C15725	CR W. Cleveland Voltage	-	150,000	150,000
C15729	North Syracuse Install Capacitors	175,000	50,000	225,000
C15749	Hurricane Rd. Rebuild	-	371,000	371,000
C16118	IE - NC ERR and Fuse	-	250,000	250,000
C24482	CR-Central Square 1562-Rebuild	-	853,000	853,000
C24959	DestiNY Expansion-subT New Swgr	-	50,000	50,000
C25261	DOT- Taft Road Relocations	-	350,000	350,000
C25404	Akwasasne Mohawk Casino Line Tap	-	250,000	250,000
C26597	Galeville Load Relief	-	120,000	120,000
C26777	Richville-Battle Hill#26 Retirement	-	1,000	1,000
C26969	Bombay-Spencer's Corners#22 Recond	-	750,000	750,000
C27984	Balmat 90461-Cole Rd Relocation	-	217,000	217,000
C28040	Niles 29451 Reconductoring	179,000	45,000	224,000
C28292	Rathbun-Labrador #39 Underbuilt	-	150,000	150,000
C28590	Gilbert Mills 51 Rebuild due to QRS	398,000	5,000	403,000
C28608	McGraw 69 Low Voltage improvement	53,000	18,000	71,000
C28611	Harris Rd 51 Rebuild	210,000	25,000	235,000
C28847	Fairdale Load Relief	264,000	62,000	326,000
C28853	Cortland Relief	234,000	50,000	284,000
C28854	Cortland 02 Relief	209,000	49,000	258,000
C28942	WHTESBR-SCHUYLER 29/YAH-WHITSBRO	-	50,000	50,000
C29102	DOTR PIN 3501.42 Bartel Rd	-	165,000	165,000
C29444	Salina Landfill 34.5kv relocations	50,000	150,000	200,000
C29496	NR-32356 RT 37 Conv.	486,000	161,000	647,000
C29944	Devoe Rd. Rebuild	-	125,000	125,000
C30132	Jefferson Commons	-	150,000	150,000
C30586	Fayetteville Retirement	-	236,000	236,000
C31063		-	97,000	97,000
C31128	Hinsdale Fdr Relief	-	273,000	273,000
C31177	St. Joe's Underground Relocation	-	172,000	172,000
C31197	DOT PIN7116.05 Rt9N AuSable Forks	-	150,000	150,000
C31349	DOT PIN 2042.33 St Rt26 &46 Rome	-	110,000	110,000
C31544	Pleasant Acres URD Phase 1	-	110,000	110,000
C31546	Pleasant Acres Subdivision Part 2	-	144,000	144,000
C31554	DOT PIN3045.55 Rt104 Osw-Scriba	-	8,000	8,000
C31560	NR-SLU Hillside Dr	-	450,000	450,000
C31672	Clinton St Beautification	-	110,000	110,000
C31730	Primary UG to 12 lots	-	120,000	120,000
CNC021	Cent NY-Dist-Telecomm Blanket	-	8,000	8,000
CN3620	NiMo Transformer Purchases	23,879,000	1,000	23,880,000

PSC Management Audit
Tranmission Reconciliation of 2009 CIP vs TRAC

Project #	Project Description	FY09/10 TRAC	FY09/10 CIP	FY10/11 TRAC	FY10/11 CIP	FY11/12 TRAC	FY11/12 CIP	FY12/13 TRAC	FY12/13 CIP	FY13/14 TRAC	FY13/14 CIP
		124,899,606	**120,609,606**	**254,409,856**	**219,639,856**	**402,811,665**	**359,391,665**	**519,490,191**	**452,280,191**	**377,642,073**	**373,512,073**
CNYPL6	transformer and some 230kV breakers at	-		-		(250,000)		(5,000,000)		(10,000,000)	
CNYAS6	NY Circuit Breaker Replacement Priority 3)	-		-		(100,000)		(1,820,000)		1,920,000	
CNYAS12	NY Bay Infrastructure Replacement (Priority 3)	-		-		(200,000)		(8,800,000)		-	
CNYPL10	Inman Road Substation	(950,000)		(2,500,000)		3,500,000		-		-	
CNYPL12	New Alps Site	(950,000)		(1,100,000)		2,100,000		-		-	
CNYAS23	Inghams - replace 115kV oil breakers	(250,000)		(750,000)		(4,000,000)		-		5,000,000	
CNYAS30	Tilden - replace 115kV oil circuit breakers	(250,000)		(1,000,000)		(9,750,000)		1,000,000		10,000,000	
CNYAS41	Menands - new control building	(250,000)		(1,000,000)		(4,750,000)		1,000,000		5,000,000	
CNYAS43	Queensbury - replace oil circuit breakers	(250,000)		(750,000)		(9,000,000)		10,000,000		-	
CNYAS10	NY Protection & Control Replacement (Priority 3)	-		-		-		(100,000)		(1,400,000)	
CNYAS11	NY Bay Infrastructure Replacement Priority 4)	(100,000)		(4,000,000)		(5,770,000)		(14,400,000)		(23,670,000)	
CNYAS17	Enhanced structure design (Phase I)	(100,000)		(2,680,000)		(2,760,000)		(2,850,000)		(2,940,000)	
CNYAS21	Improved fault location	(100,000)		(390,000)		(490,000)		(490,000)		(490,000)	
CNYPL13	Fourth Sawyer 230-23kV Bank (N-1-1)	(100,000)		(650,000)		(650,000)		(3,900,000)		(8,200,000)	
CNYPL14	Fourth Elm 230-23kV Bank (N-1-1)	(100,000)		(650,000)		(650,000)		(3,900,000)		(8,200,000)	
CNYPL15	Reconductor 115kV Circuits #54 and #181	(100,000)		(300,000)		200,000		(3,100,000)		1,300,000	
CNYPL16	Homer Hill 15kV Capacitor bank	(100,000)		(300,000)		-		(700,000)		1,100,000	
CNYPL17	Dunkirk second 115kV bus tie breaker	(100,000)		(300,000)		-		(700,000)		1,100,000	
CNYPL18	Huntley second 230kV bus tie breaker	(100,000)		(200,000)		-		(900,000)		100,000	
CNYPL19	Packard second 230kV bus tie breaker	(100,000)		(200,000)		-		(900,000)		100,000	
CNYPL20	Lockport second 115kV bus tie breaker	(100,000)		(300,000)		-		(700,000)		1,100,000	
CNYPL21	Batavia 115kV Capacitor bank	(100,000)		(300,000)		-		(700,000)		1,100,000	
CNYPL22	Golah second 115kV bus tie breaker	(100,000)		(300,000)		-		(700,000)		1,100,000	
CNYPL23	Mortimer second 115kV bus tie breaker	(100,000)		(300,000)		-		(700,000)		1,100,000	
CNYAS19	Line segmentation (Phase I)	10,000		(50,000)		(6,100,000)		-		-	
CNYAS24	Meco - Replace 115kV PTs and circuit breakers	-		(250,000)		(750,000)		(9,000,000)		10,000,000	
CNYAS25	Whitehall - replace 115kV oil circuit breakers	-		-		(250,000)		(750,000)		(9,000,000)	
CNYAS37	control building	-		(250,000)		(750,000)		(9,000,000)		10,000,000	
CNYAS33	Porter 230kV - protection replacement	-		-		-		(100,000)		(500,000)	
CNYAS38	disconnects	-		-		(250,000)		(750,000)		1,000,000	
CNYAS39	Mortimer 115kV - refurbish / replace circuit breakers	-		-		-		(250,000)		(750,000)	
CNYAS44	circuit breakers	-		(250,000)		(750,000)		(9,000,000)		10,000,000	
CNYAS46	Flood mitigation	-		(1,000,000)		(2,000,000)		-		-	
CNYX31	Reserve Line	-		(15,000,000)							
		120,609,606	120,609,606	219,639,856	219,639,856	359,391,665	359,391,665	452,280,191	452,280,191	373,512,073	373,512,073
Check		**120,609,606**	**120,609,606**	**219,639,856**	**219,639,856**	**359,391,665**	**359,391,665**	**452,280,191**	**452,280,191**	**373,512,073**	**373,512,073**
Var to CIP		-	-	-	-	-	-	-	-	-	-
TRAC Change		**(4,290,000)**		**(34,770,000)**		**(43,420,000)**		**(67,210,000)**		**(4,130,000)**	