October 5, 2012

Hon. Jaclyn A. Brilling, Secretary
New York Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

RE: Case 08-M-0152 – Comprehensive Management Audit of Consolidated Edison Company of New York, Inc.

Dear Secretary Brilling:

Consolidated Edison Company of New York, Inc. ("the Company" or "CECONY") filed its Audit Implementation Plan ("AIP") on October 5, 2009 outlining its plans to implement the recommendations provided in the Management Audit Report ("Audit Report") issued in the referenced proceeding. Since we began implementing the recommendations from the Audit Report, we have been sharing the progress being made through periodic comprehensive updates with the Public Service Commission ("PSC" or "Commission"). Attached is the Company’s tenth update and third Annual Report on our implementation progress, which covers the period from October 5, 2011 through October 4, 2012. We are providing this update pursuant to the provisions of the Commission’s August 21, 2009 “Order Directing the Submission of an Implementation Plan” in this proceeding and March 26, 2010 “Order Establishing Three Year Electric Rate Plan” in Case 09-E-0428. An electronic copy of the Company’s AIP update report is provided herewith for electronic filing. In addition, the Company is also sending five hardcopies to Kathleen Tallmadge via overnight mail.

The Audit Report resulted in 92 recommendations in the areas of Corporate Planning, Board Oversight, Load Forecasting, System Planning, Budgeting, Work Management, Cost Management, Project Management, Supply Procurement, Incentive Compensation and Performance Measures. Implementation has included a comprehensive Company-wide effort to engage our employees, as well as to work with Staff and other parties as appropriate. The Company has taken an integrated and holistic approach in addressing each of these recommendations. The Company created twelve executive-led teams, and each
recommendation and associated conclusions were assigned to a team based on the nature of the issues presented. Oversight of implementation was assigned to two senior vice presidents who have been coordinating the Company’s response to the recommendations so that the recommendations are addressed in an integrated fashion. Throughout the process, the Con Edison Board and senior management have taken a leadership role in view of the significance of the audit implementation effort to the Company’s operations and its overall strategic vision. We have adopted measures to sustain these efforts in our business practices.

The Company has implemented 91 of the Audit Report’s 92 recommendations. Implementation of the remaining recommendation, Electric Work Management System, is under way and is planned to be completed in March 2014. Beyond the 92 recommendations, the Audit Report also described “barriers” that need to be addressed in order to facilitate the future sustainability and success of the Company. These barriers were described as root cause issues, and were identified in four areas: cultural, regulatory, financial and environmental. The Company has been addressing these barriers, both directly through the work of our culture change efforts and the Company-PSC Staff Barriers Team, and also through our work to implement the audit recommendations as the recommendations also typically impact one or more of the barriers.

**The Year in Review**

We continue to take steps, led from the highest levels of the Company, to strengthen our company’s culture, refine our long range planning work, maintain our cost management efforts, and enhance our external relationships. Ultimately, our goal is to create long term benefits for our customers, thereby better positioning Con Edison for a sustainable future.

Our implementation started with a Company-wide “call to action” led by our Board and senior executives. Our Board continues to be a driving force, and in the last three years has implemented changes to its committee structure and calendar, created dashboards for each committee as indicators of Company performance, and revised its delegation of authority to require pre-approval for large high priority projects. In 2012 the Board approved a number of large capital projects pursuant to the revised delegation of authority. Moreover, the Company has added a metric for management of major O&M and capital projects as a key performance indicator. These actions have enhanced Board oversight and the quality of discussions about business performance among the Board, its committees, and management.

Our senior executives continue to take the lead in our culture change and putting it into action. In 2012 our Corporate Leadership Team, comprised of the Company’s senior officers, identified several culture based initiatives intended to move the culture forward in our three cultural imperatives: enhance customer and other external relationships; engender openness, fairness, and trust; and reinforce a cost management consciousness. Major initiatives included performance management changes to drive for a higher performing culture and a review and
revision of employee compensation and benefits to attract and retain a qualified and high performing workforce.

In 2012 Con Edison strengthened our leadership’s commitment to cultural transformation through the creation of two new officer-led organizations. The first, Vice President of Business Finance, will further promote cost management and a cost consciousness mindset in our corporate culture by consolidating our financial planning, budgeting, and forecasting functions under one organization. The second, Vice President of Business Ethics and Compliance, will enhance our commitment to openness, fairness and trust in our corporate culture.

We have also extended our efforts at long term planning, with an integrated long range plan, going beyond the initial management audit recommendation. The expanded effort identified over $6 billion in cost savings, deferrals, and avoidances across the three commodities over the 20-year planning horizon, which is $2 billion greater than the savings and cost avoidance identified in 2010 long range plans. The ILRP focuses on three key objectives: minimizing customer energy use, improving our use of existing assets, and reducing all components of our customers’ bills. The first two objectives are aimed at reducing our customers’ delivery costs, which make up approximately one-third of their bills. We aim to reduce delivery costs first by reducing demand, then by using our assets more efficiently to meet that demand. The third goal addresses the remaining components of our customers’ bills—energy supply cost, and taxes and fees.

Our efforts to reduce customer peak demand, where applicable, will lower our infrastructure costs and improve the utilization of our existing utility infrastructure. We are also helping our customers reduce their overall energy usage by offering various conservation and energy efficiency programs. We are working with customers to offer a broader range of energy solutions that consider customer and system impacts and result in the optimal use of the three commodities. For example, our energy solutions will consider such options as oil-to-gas conversions and steam air conditioning if beneficial to customers. We will also incorporate customer-sited combined heat and power or other distributed generation resources into our planning processes, provided they have a track record of reliable performance. We will improve our use of existing assets by relying on refined system modeling and robust cost-benefit analyses for all of our projects so that we can make more informed decisions. We continue to work on behalf of customers to influence energy supply components of the bill, by maintaining a strong presence in various regulatory and wholesale market forums, where we advocate for policies and standards that result in fair, competitive customer supply costs, while maintaining reliability and preserving the integrity of the wholesale markets. Similarly, we are pursuing opportunities to lower the taxes and fees portion of our customer bills. For example, the company is actively working with NYSERDA in its implementation of Renewable Portfolio Standard and System Benefits Charge programs to make sure the benefits match cost to customers.
Con Edison aims to achieve long term benefit for our customers through the Company’s investments. The Management Audit recommendations facilitated improvements in our asset management strategies, energy efficiency initiatives, work management practices and project and program management. Each has resulted in benefits for our customers. We continue to improve our asset management strategies as part of our long range planning initiatives, and, to date, have achieved cost avoidances of approximately $82 million in our electric transmission and distribution capital spending by using these strategies. We continue to integrate new and innovative planning and design strategies to reduce our capital investment requirements and to improve the use of our existing assets. We look to meet our service reliability objectives with less asset-intensity by implementing innovative third-generation (3G) designs. The key strategies, or design concepts, that achieve cost reductions include substation asset sharing, distribution load transfer, feeder reconfiguration, low voltage network migration and smart grid implementation.

Our demand side management and energy efficiency initiatives are helping us to reduce greenhouse gas emissions, decrease the demand for energy, and contain costs. The Company now includes the impact of energy efficiency savings in our demand forecasts, which lowers future needs for infrastructure, further mitigating costs impacts for customers. Con Edison is deploying new technology to address NYC-specific efficiency needs, such as a modular, internet-controllable plug for room air conditioning that allows Con Edison to cycle room AC units during system events.

We continue to implement a new work management system in our Electric Operations organization. We expect to realize total annual savings of $45 million net of ongoing information technology maintenance expenses upon full implementation in 2014.

We have improved our resource management capabilities through the use of new human resource planning tools, balancing in-house and external engineering design resources, merging our energy supply hedging functions and consolidating our vegetation management contractor management functions. We have identified savings of approximately $850,000 annually through these resource planning improvements.

We are being vigilant in evaluating our costs. Cost consciousness has become a part of the way we work, and more and more we are seeing examples of our employees acting with cost consciousness and using cost management techniques. During work execution our employees are being held to stringent goals and objectives for cost management. Con Edison has established a Cost Management Sustainability Team, which acts as a forum for the communication and exchange of cost management best practices and new ideas.

This year we implemented Project One, a new integrated finance and supply chain system for the Company. Through the implementation we have enhanced processes used by employees
to purchase materials, manage inventory, develop business plans, and record financial data. The new system enables us to improve our data analysis including cost analysis and financial forecasts.

The Company is maintaining its efforts to foster an outward focus. We continue to make progress with respect to the barriers Liberty identified, and are making greater efforts to be open and invite feedback. Throughout the audit process and beyond, we have and continue to work with the Commission and its staff, local governments, the media, our customers, and other external stakeholders. Con Edison is using new technology, including social media, to support this outward focus in addition to its traditional communications activities. We recently earned top Public Relations industry awards from Ragan Communications and Bulldog Reporter for our digital & social media communications during Hurricane Irene. We have continued to invite the media into our command center, providing them with an opportunity to interview Incident Commanders and learn first-hand how decisions are made and how the Company handles emergencies.

A key initiative in addressing the barriers has been the joint effort between the Company and the PSC and its Staff to address barrier issues. After a few years of working collaboratively to jointly address the barriers, Staff has recognized the progress the Company has achieved in mitigating the cultural, financial and environmental barriers. In addressing the regulatory barrier, we were able to reevaluate and modify certain regulatory mandates that were no longer needed. The Company continues work to address all barrier issues through our day-to-day actions, and will continue to engage Staff regarding our progress.

Summary of Recommendation Completion Status by Team
Within this update, the Company explains progress it has made to address each of the audit’s 92 recommendations. Ninety-one of these recommendations have been fully implemented. Each team’s completion status is summarized below:

<table>
<thead>
<tr>
<th>Team(s)</th>
<th>Recommendation Status</th>
<th>Complete</th>
<th>Outstanding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team 1: Electric Long Range Plan</td>
<td>10 of 10 complete</td>
<td>1, 2, 3, 4, 5, 21, 22, 34, 39, 42</td>
<td></td>
</tr>
<tr>
<td>Team 2: Board Leadership</td>
<td>5 of 5 complete</td>
<td>6, 7, 8, 43, 56</td>
<td></td>
</tr>
<tr>
<td>Team 3: Rate &amp; Financial Strategy</td>
<td>1 of 1 complete</td>
<td>41</td>
<td></td>
</tr>
<tr>
<td>Team 4: Work Management</td>
<td>6 of 7 complete</td>
<td>32, 33, 44, 51, 67, 72</td>
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</tr>
<tr>
<td>Team 5: Cost Management</td>
<td>16 of 16 complete</td>
<td>9, 10, 40, 45, 46, 47, 48, 49, 50, 52, 62, 65, 68, 69, 70, 73</td>
<td></td>
</tr>
<tr>
<td>Team 6: Load Forecasting</td>
<td>10 of 10 complete</td>
<td>14, 16, 17, 18, 19, 20, 23, 79, 80, 82</td>
<td></td>
</tr>
<tr>
<td>Team 7: Gas Main Replacement</td>
<td>1 of 1 complete</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>Team 8: Gas Capacity Planning</td>
<td>3 of 3 complete</td>
<td>15, 86, 87</td>
<td></td>
</tr>
</tbody>
</table>
One recommendation remains outstanding: recommendation 71, which is associated with our efforts to implement a new work management system for our electric distribution operations, and is scheduled to be completed by March 2014.

Content of the Audit Implementation Plan Annual Report and Update
Within this report, the Company summarizes actions taken over the last year to address the Audit Report’s findings and recommendations. It includes the following sections:

I. Executive Summary: This section highlights the Company’s progress to date.

II. Background: This section provides background on the audit, its findings and recommendations, including the barriers.

III. Strategic Response to the Management Audit: This section details the Company’s response, including a discussion of Board of Trustee engagement, governance structure for implementation, and our Guiding Principles for Implementation.

IV. Update for the Year: The Company completed one recommendation in its third year of implementation. This section summarizes the activities for this newly completed recommendation.

V. Continuing Cultural Transformation: This section provides a summary of the Company’s ongoing cultural transformation efforts. It addresses each of the Company’s three cultural imperatives, and provides examples of initiatives.

VI. Addressing the Barriers: The Company’s efforts to mitigate its cultural, financial, regulatory, and environmental barriers are discussed in this section.

VII. Integrated Long Range Planning: The Company’s long range planning initiatives are discussed in this section.
VIII. **Sustainability:** This section discusses the Company’s efforts for the 91 completed recommendations to show how we are sustaining them.

IX. **Cost, Benefit, and Risk Analysis:** This section explains the Company’s approach to evaluation of costs, benefits, and risks throughout implementation.

X. **Discussions with PSC Staff:** The innovative approach to the Management Audit and its implementation has provided meaningful feedback and direction for the Company’s improvement. This section describes the enhanced approach to communication.

XI. **Recommendation Completion and Status:** This section explains the report’s appendices and provides an overall status update.

XII. **Conclusion:** This is the final section in this Annual Report.

XIII. **Appendices:** Three appendices that were included with our original Audit Implementation Plan (AlP) and each update filing are included; updates to each since our last update filed on June 5, 2012 are discussed below. One additional appendix is included for this filing: Appendix D provides an updated costs and benefits summary for each recommendation.

**Changes to the Original Audit Implementation Plan Appendices**

Three appendices are enclosed, each of which was submitted with our original Audit Implementation Plan (AlP) on October 5, 2009 and has been included in each of our updates.

- **Appendix A:** The table in Appendix A correlates the Company’s recommendation numbering sequence to that found in the Audit Report. This appendix has not changed.

- **Appendix B:** Each recommendation’s Assessment (“Accepted”, “Modified”, “Under Review”, or “Not Accepted”); Status (“In Progress”, “Completed”, “Pending”, or “Reevaluating”); and key dates and expected results are provided in Appendix B. This appendix has been updated to reflect newly available cost benefit and risk analysis information.

- **Appendix C:** A summary of implementation actions for each recommendation is included in Appendix C. For each completed recommendation, a comprehensive summary of implementation actions is provided. For the one outstanding recommendation, Recommendation 71, the update provided in Appendix C details updated information reflecting changes to key dates and status for each major activity and milestone. For this recommendation, a “September 15, 2012 Update” summarizes
work completed since May 15, 2012, the coverage date of the last AIP update filed on June 5, 2012.

Additional Appendix Included as Part of the Company's Annual Report
One additional appendix is included in this Annual Report: Appendix D. While not included in the 2009 AIP, we added this appendix to the 2010 and 2011 Audit Implementation Plan Annual Report and Update documents, and include it again in this year’s update.

- Appendix D: A cost benefit summary for each recommendation is included in tabular format as Appendix D. This summary includes the cost benefit forecast at the time of each completed recommendation's close-out, and also an update against those expectations through the current time for recommendations where new information is available. We have revised Appendix D to include savings identified in the 2011 Audit Implementation Plan Annual Report and Update reports.

Next Steps
We are continuing to take steps, led from the highest levels, to strengthen our culture, be sustainable for the long term, enhance our customer service levels, and be even more engaged with all of our stakeholders. We continue to work on each of our cultural imperatives and are continuing to create benefits for our customers through our long range planning activities, asset management strategies, and our cost and resource management initiatives. We continue to look to improve our operations and create sustained benefits for customers.

Sincerely,

Enclosure
cc: Kathleen Tallmadge
    Henry Leak, III
    Kristee Adkins
Audit Implementation Plan
Annual Report and Update

Consolidated Edison
Company of New York, Inc.
Case 08-M-0152

October 5, 2012
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I. Executive Summary

In February 2008, the Public Service Commission (“PSC”) initiated a comprehensive management audit of Consolidated Edison Company of New York Inc.’s (“Con Edison”) electric, natural gas, and steam businesses, with a specific focus on the Company’s construction program, planning processes, and operational efficiency. The Liberty Consulting Group was retained by the PSC to conduct the audit. The audit began in May 2008, and the final Audit Report was issued in August 2009. The report included 92 recommendations and also identified four barriers that deal with greater challenges the Company faces, particularly in the long term. The barriers are in culture, regulatory, environmental, and financial areas.

Since submitting its initial Audit Implementation Plan in October 2009, Con Edison has been providing formal update reports every four months and an annual update report each October to the Public Service Commission. This is the Company’s third annual report.

Within this report, we provide detailed descriptions on the progress we are making with respect to implementation of each of the 92 recommendations, our internal culture transformation efforts, progress in addressing the barriers identified by Liberty, the integrated long range planning process, sustainability, and the costs and expected benefits to the Company and our customers of implementing recommendations.

We have completed 91 of the Audit Report’s 92 recommendations. While we are nearly complete with our planned implementation as set forth in our Audit Implementation Plan, we recognize that our challenge does not end there. We will sustain our efforts through continuous improvement of our business practices.

Strengthening the Company

We continue to take actions, led from the highest levels, as we work to strengthen our culture and better position Con Edison for the future. Our Board was involved from the start, and they continue to be a driving force. In addition to providing overall direction and oversight to the Management Audit, our Board had five specific audit recommendations that dealt directly with their involvement in Company operations. All five have been completed. We revised our Board committee structure to better coordinate functions and focus on infrastructure planning, oversight, and performance measurement. The Finance Committee and the Board added a requirement for Finance Committee pre-approval of new projects with an estimated cost in
excess of $50 million, and full Board pre-approval of new projects with an estimated cost in excess of $100 million. We also built successful management of major O&M and capital projects into our Key Performance Indicators. These actions have enhanced Board oversight and the quality of discussions about business performance among the Board, its committees, and management.

Con Edison is continuing on its path to transform our corporate culture. We remain committed to making cultural changes by seeking opportunities to leverage our strengths and address our challenges. Our cultural transformation efforts continue to be led by our Corporate Leadership Team (CLT). In 2012 CLT identified several culture based initiatives intended to move the culture forward in our three cultural imperatives which are as follows: enhance customer and other external relationships; engender openness, fairness, and trust; and reinforce a cost management consciousness. Recent major initiatives included performance management changes to drive for a higher performing culture and a review and revision of employee compensation and benefits to attract and retain a qualified and high performing workforce.

To further strengthen our leadership’s commitment to cultural transformation, two new officer-led organizations were created this year. The first, Vice President of Business Finance, will further promote cost management and a cost consciousness mindset in our corporate culture by consolidating our financial planning, budgeting, and forecasting functions under one organization. This consolidation will create a greater alignment in the Company’s short and long range plans, promote best practices in cost management and improve financial performance.

The second, Vice President of Business Ethics and Compliance, will enhance our commitment to openness, fairness and trust in our corporate culture. The Vice President of Business Ethics and Compliance is responsible to oversee the Company’s Standards of Business Conduct, coordinate the Company’s Business Ethics and FERC compliance training and communication programs, issue Corporate Policy Statements and Corporate Instructions and conduct Business Conduct Investigations. This new organization will increase our focus on the requirement for all employees to act with the highest levels of integrity and ethics.

We continue to observe signs of culture change at many levels of the Company as our cultural imperatives are becoming part of the way we work and integrated into the way we do business. We recognize that we have a long journey ahead of us to achieve total cultural transformation, and we expect to meet challenges along the way. We have taken important steps in laying the groundwork for this company-wide effort.
Long Range Planning

In 2010, we published long range plans for our electric, gas, and steam systems. These plans included our expectation of customer demand on our systems for the next 20 years, and the infrastructure that would be required to safely and reliably accommodate our customers’ energy demand for each of the three commodities, electric, gas, and steam. We also estimated the investments required to accommodate this demand, and the corresponding impact on customer bills. Each of the plans is a road map to our departmental business plans and annual and long term budgets, and we have been closely monitoring our progress. Our 2010 electric, gas and steam long range plans identified about $4 billion in estimated cost savings and avoidances over the 20-year planning horizon.

In 2012, we issued an Integrated Long Range Plan (“ILRP”) that updated each commodity’s 2010 long range plan and also identified areas where integration would create synergy among our electric, gas, and steam businesses. The ILRP will optimize our plans for meeting our customers’ energy demand, while providing more value for our customers.

We have applied a common framework to our infrastructure-planning process across the three commodities. Our long-term forecasts are based on a common set of basic data, assumptions and industry trends.

In the ILRP, we have identified over $6 billion in cost savings, deferrals, and avoidances across the three commodities over the 20-year planning horizon, which is $2 billion greater than the savings and cost avoidance identified in 2010 long range plans.

The ILRP focuses on four key goals: minimizing customer bill impacts (focusing on total customer bill which includes supply, taxes, and fees), improving customer service, maintaining reliability, and meeting environmental goals (i.e., Con Edison, NYS, and NYC environmental goals).

To achieve the first goal of minimizing customer bill impacts, the ILRP addresses three key objectives: minimizing customer energy use, improving our use of existing assets, and reducing all components of our customers’ bills. The first two objectives are aimed at reducing our customers’ delivery costs, which make up approximately one-third of their bills. We aim to reduce delivery costs first by reducing demand, then by using our assets more efficiently to meet that demand. The third objective addresses the remaining components of our customers’ bills—energy supply cost, and taxes and fees.
First, we will help our customers lower their demand and energy consumption. Our efforts to reduce customer peak demand, where applicable, will lower additional infrastructure costs and improve the utilization of our existing utility infrastructure. We are also helping our customers reduce their overall energy use by offering various conservation and energy efficiency programs.

We are working with customers to offer a broader range of energy solutions that considers customer impacts and the optimal use of the three commodities. For example, our energy solutions will consider such options as oil-to-gas conversions and steam air conditioning if beneficial to customers. We will also incorporate customer-sited combined heat and power or other distributed generation resources into our planning processes, provided they have a track record of reliable performance. Cost-effective solutions will be considered where they can provide direct benefits to participating customers, while reducing our system peak demand, and allowing us to defer large capital investments for the benefit of all customers.

Second, we will improve our use of existing assets to reduce capital investment and therefore lower customer costs. With the help of new technologies, systems and processes, we seek to make better use of existing assets with spare capacity, rather than make an additional infrastructure investment. To this end, we rely on refined system modeling and robust cost-benefit analyses for all of our projects so that we can make more informed and cost effective decisions. We are standardizing our work processes through improved project management and work management systems.

Third, we recognize that our customers’ bill includes not only our delivery costs, but also taxes, fees, and wholesale energy costs. We continue to work on behalf of customers to influence energy supply components of the bill. We maintain a strong presence in various regulatory and wholesale market forums, where we advocate for policies and standards that result in fair, competitive customer supply costs, while maintaining reliability and preserving the integrity of the wholesale markets. Similarly, we are pursuing opportunities to lower the taxes and fees portion of our customer bills.

**Creating Long Term Benefits for Our Customers**

On a long term and sustained basis, we remain committed to focusing on our customers’ needs and considering the impact of our actions on their bills as we carry out our mission to provide safe and reliable service. The Management Audit recommendations facilitated improvements
in our asset management strategies, energy efficiency initiatives, work management practices and project and program management. Each has resulted in benefits for our customers.

We continue to improve our asset management strategies as part of our long range planning initiatives, and, to date, have achieved cost avoidances of approximately $82 million in our electric transmission and distribution capital spending by using these strategies. Our asset optimization strategies are aimed at targeting investments where they are needed most, and where possible eliminating investments that are not cost effective or have a lower return on investment. For example, we conducted detailed analysis of 22 electric distribution capital reliability programs so investment is prioritized to meet system performance needs. This approach resulted in a quantified cost-benefit analysis to target investments to those programs yielding the greatest projected benefit for a given investment, and reducing or eliminating investment in those programs not shown to provide benefit.

We continue to integrate new and innovative planning and design strategies to reduce our capital investments and to improve the use of our existing assets. We look to meet our service reliability objectives with less asset-intensity by implementing innovative third-generation (“3G”) designs. These designs are a critical component of our infrastructure-planning framework, allowing us to increase asset utilization and reduce our investment requirements. The key strategies, or design concepts, that achieve cost reductions include substation asset sharing, distribution load transfer, feeder reconfiguration, low voltage network migration and smart grid implementation.

Our demand side management and energy efficiency initiatives continue to play a larger role in the Company’s strategy to reduce greenhouse gas emissions, decrease the demand for energy, and contain costs. We have made substantial progress toward the megawatt hour (MWh) energy savings achievements specified by the Public Service Commission, resulting in environmental and cost benefits for all our customers. The Company now includes the impact of those energy savings in our demand forecasts, which lowers future needs for infrastructure, further mitigating cost impacts for customers. By working closely with the Company’s engineering and planning functions, energy efficiency professionals design energy efficiency programs that directly address future infrastructure or planning needs, for example by targeting energy efficiency efforts to relieve strain on the secondary distribution system. Con Edison is deploying new technology to address NYC-specific efficiency needs, such as the modular, internet-controllable plug for room air conditioning units called a “modlet” that was the result of a patent filed by Con Edison energy efficiency personnel. This ‘modlet’ allows Con Edison to cycle room AC units during system events, enabling customers to participate in conservation efforts during high peak periods.
We continue to implement a new work management system in our Electric Operations organization. We expect to realize total annual savings of $45 million net of ongoing information technology maintenance expenses upon full implementation in 2014.

We have and will continue to see project management savings through productivity improvements related to capital project and program expenditures. While savings will vary depending on the size and scope of the projects and programs included in this new approach, we estimate annual savings of approximately $10 million.

We have improved our resource management capabilities through the use of new human resource planning tools, balancing in-house and contractor engineering design resources, merging our energy supply hedging functions and consolidating our vegetation management contractor management functions. We have identified savings of approximately $850,000 annually through these resource planning improvements.

We developed and implemented a Strategic Alignment Methodology to evaluate certain capital projects company-wide to help make investment decisions after determining the relative benefit, cost and risk. This methodology improves the alignment of our capital project investments to the corporate strategy and other long-term goals.

**Vigilance in Cost Consciousness and Cost Management**

We are working to create a culture of cost consciousness in which we all seek and accept the responsibility that everyone must manage cost. Cost consciousness has become a part of the way we work, and more and more we are seeing examples of our employees acting with cost consciousness and using cost management techniques.

Our planning and budgeting functions place a greater emphasis on cost consciousness and management. Each department must identify and quantify cost saving initiatives in their annual and long term plans. During work execution our employees are being held to stringent goals and objectives for cost management. To help our employees achieve our cost goals and objectives we continue to implement new cost management tools and provide training and communication on project and work management best practices. Key performance indicators facilitate our achievement of cost management goals and we have incorporated cost management into our employee performance management system. These efforts along with others continue to drive us towards a culture of cost consciousness.
A key effort in our cost management strategy was the development of The Cost Management Sustainability Team. They continue to act as forum for the communication and exchange of cost management best practices and new ideas. This team’s mission is to sustain our cost management strategy and guiding principles and deploy cost management methods company-wide. The team is comprised of General Managers and Cost Managers from all areas of the Company and they are tasked with promoting and sustaining cost management initiatives throughout the Company.

This year we implemented Project One, a new integrated finance and supply chain system for the Company. Through the implementation we have enhanced processes used by employees to analyze data, purchase materials, manage inventory, develop business plans, and record financial data. The new system will enable us to improve our cost analysis and financial forecasts.

More Intense Outward Focus

We continue to make progress with respect to the barriers Liberty identified, and are making greater efforts to be open and invite feedback. Throughout the audit process and beyond, we have actively engaged the PSC and its Staff, local governments, the media, our customers, and other external stakeholders. We are seeking greater input and are working with others towards reaching common goals. With common goals and understanding we can better serve the electric, gas and steam customers of New York City and Westchester County.

Con Edison recognized early on the importance of incorporating the use of new technology into its traditional communications activities. The Company’s social media platforms, Facebook, Twitter, and YouTube, are used to provide customers, media, elected officials and members of the community with an alternative way to obtain important Con Edison information such as outage information, estimated restoration times, safety tips, energy efficiency tips and other Company news. We recently earned top Public Relations industry awards from Ragan Communications and Bulldog Reporter for our digital and social media communications during Hurricane Irene.

Con Edison has taken great strides to communicate more frequently and transparently during storms and heat waves, allowing the media into its command center where they can film and record emergency personnel in action, communicating with field personnel and observing
conference calls. They get an opportunity to interview Incident Commanders and learn first-hand how decisions are made and how the Company handles emergencies.

A key initiative in addressing the barriers has been the joint effort between the Company and the PSC and its Staff to mitigate barrier issues. After a few years of working collaboratively to jointly address the barriers, Staff has recognized the successes the Company has achieved in mitigating the cultural, financial and environmental barriers. In addressing the regulatory barrier, we were able to reevaluate and modify certain regulatory mandates that were no longer needed. The Company continues work to address all barrier issues through our day-to-day actions, and will continue to engage Staff regarding our progress.

**Conclusion**
We are continuing to take steps, led from the highest levels, to strengthen our culture, be sustainable for the long term, enhance our customer service levels, and be even more engaged with all of our stakeholders. We continue to work on each of our cultural imperatives and are continuing to create benefits for our customers through our long range planning activities, asset management strategies, and our cost and resource management initiatives. We continue to look to improve our operations and create sustained benefits for customers.
II. Background

In February 2008, the New York Public Service Commission (“Commission”, or “PSC”), in Case 08-M-0152, ordered a comprehensive management audit of Consolidated Edison Company of New York, Inc. (“Con Edison”, “the Company”, or “CECONY”) in accordance with Public Service Law, Section 66(19). The PSC selected the Liberty Consulting Group (“Liberty”) to perform a comprehensive management audit of the Company’s electric, natural gas, and steam businesses, with a specific focus on the Company’s construction program, planning processes, and operational efficiency. From its start in June 2008, Con Edison, PSC Staff, and Liberty worked collaboratively to facilitate this review of the Company’s management process.

The audit concluded in the spring of 2009, and the final report was issued on August 7, 2009. The report included 119 conclusions and 92 recommendations, and identified four barriers that Liberty stated may limit Con Edison’s ability to deal with the challenges it faces, particularly in the long term. The barriers are in culture, regulatory, environmental and financial areas.

Since submitting its initial Audit Implementation Plan (“AIP”) on October 5, 2009, the Company has been providing formal update reports every four months. Con Edison and PSC Staff continue to work collaboratively throughout implementation of the audit’s recommendations.

The Management Audit

This management audit was different from a traditional audit in several regards. For one, the process was collaborative and open. Second, the audit scope included a comprehensive examination of the multiple aspects of the Company’s management process, particularly with respect to the planning and implementation of the Company’s capital and operations and maintenance (O&M) programs.

The audit was based on a framework of eight distinct elements that are tied together into a continuous feedback loop, beginning with the “corporate mission, objectives, goals and planning” and progressing through “performance and results measurement” to review how the Company’s objectives are achieved. (See Figure 1). This approach allowed us to demonstrate what the Company does well and to examine what improvement can be made in the areas of planning, operations and management process.
The process is consistent with our Way We Work principle of continuous improvement in our business processes. Improvements will enable us to operate more effectively and efficiently and continue to provide our customers with reliable and safe service at reasonable cost. Throughout the audit, as Staff and Liberty identified issues, they discussed them as “strawman” proposals with the Company in order to seek ways to determine the appropriate resolutions collaboratively. In this strawman process, Liberty laid out preliminary findings and conclusions and worked with Con Edison to evaluate and respond to the Liberty hypotheses, and, if appropriate, to better define the issues and seek beneficial solutions. Each of these strawman proposals evolved as dialogue progressed, and all were present in the final report. This collaborative process resulted in thorough discussions, acceptance, and the start of implementation of all eight major strawman proposals substantially earlier than the issuance of the final Audit Report.¹

The Company fully endorsed Liberty’s suggestion of using a collaborative audit approach in future management audits. We believe that collaborative efforts led to better understanding of issues and, therefore, better solutions. We recommend that this process be continued in the future.

¹ Liberty Consulting introduced the strawmen in the following areas: electric master plan concept; the Board’s role in long term planning; ramifications of annual rate case cycle; work management; cost management; gas peak capacity planning; and two in the area of load forecasting.
From the start, we took steps to ensure that the audit and its implementation would provide real and sustainable results. Along with numerous people who are involved in implementing audit recommendations, we maintained a dedicated full-time team to facilitate the audit process. We embraced the idea of being involved in the process and having the opportunity to offer solutions to issues that arose during the audit process.

Since submitting its initial Audit Implementation Plan on October 5, 2009, the Company has been providing formal update reports every four months.

In this third annual report, the Company provides a comprehensive discussion of its implementation activities, including a discussion of its progress with respect to the cultural and other barriers identified in the Audit Report, and provides an updated estimate of quantitative and qualitative benefits to customers and the Company.

**Audit Findings**
The Audit Report culminated in 119 conclusions and 92 recommendations which Liberty presented in the form of a pyramid. (See Figure 2)
The Audit’s Specific Recommendations

The bottom tier of the pyramid presents process and strategy issues that are associated with typical audits. These include planning, budgeting, reporting and oversight, and commodity supply. This tier encompasses the majority of the audit’s individual recommendations and entails tactical actions to accomplish specific improvements.

The 92 recommendations from the audit are distributed across 12 categories shown in Table 1 below. Also see Appendix A - Key of Recommendations - for the Con Edison numerical recommendation sequencing as cross referenced with the Audit Report’s recommendation sequencing.

<table>
<thead>
<tr>
<th>Category</th>
<th>Number of Recommendations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporate Planning</td>
<td>5</td>
</tr>
<tr>
<td>Oversight</td>
<td>5</td>
</tr>
<tr>
<td>Incentive Compensation</td>
<td>2</td>
</tr>
<tr>
<td>Performance Measures</td>
<td>1</td>
</tr>
<tr>
<td>Load Forecasting</td>
<td>10</td>
</tr>
<tr>
<td>System Planning – Electric</td>
<td>11</td>
</tr>
<tr>
<td>System Planning – Gas</td>
<td>3</td>
</tr>
<tr>
<td>System Planning – Steam</td>
<td>1</td>
</tr>
<tr>
<td>Budgeting</td>
<td>6</td>
</tr>
<tr>
<td>Work Management</td>
<td>23</td>
</tr>
<tr>
<td>Project Management – Electric</td>
<td>6</td>
</tr>
<tr>
<td>Project Management – Gas</td>
<td>3</td>
</tr>
<tr>
<td>Project Management – Steam</td>
<td>2</td>
</tr>
<tr>
<td>Procurement – Electric</td>
<td>6</td>
</tr>
<tr>
<td>Procurement – Gas</td>
<td>8</td>
</tr>
</tbody>
</table>

(Table 1)

The Company has taken an integrated and holistic approach in addressing these recommendations. We created 12 teams, and each recommendation and associated conclusions were assigned to a team based on the nature of the issue(s) presented. Each of the 12 teams is sponsored by one or more senior officers in the Company. Two additional teams, a barriers and an internal culture team, were formed to address barriers. (See Figure 3)
Management Issues
The middle tier of the pyramid introduces four overarching management issues affecting the construction and infrastructure management programs: electric long range plan, Board engagement, rate and financial strategy, and cost management. These four areas, each originally a strawman issue, are topics of fundamental importance to the overall management of the Company’s construction and infrastructure management programs. The four areas are addressed by specific recommendations, and the resulting improvements inform and enhance the Company’s implementation of the balance of recommendations in each of the 12 categories.

The Barriers
The topmost tier of the pyramid represents the “barriers” that Liberty stated may limit Con Edison’s ability to deal with the challenges it faces, both today and in the long term. The barriers represent internal and external root causes that drive the Company’s business performance. The Audit Report states that these barriers may threaten the Company’s sustainability and ability to manage its business effectively. These barriers identify difficult challenges the Company must successfully mitigate and manage. The barriers are identified in these four areas: culture, regulatory, environmental and financial.

Liberty illustrated the four barriers and the interrelationships among them in the following diagram:
Liberty described each of these barriers as follows:

**Cultural Barriers:**
Liberty stated, “CECONY has a long-established culture that has many positive service-oriented elements. However, it is also an organization that has trouble seeing itself as others see it. In particular, the Company finds it very difficult to see different ways of doing things, and can be entrenched about its commitment to the wisdom of today’s approaches. Coupled with a defensiveness borne in part of the external pressures of operating in an immensely bright spotlight, these traits work against making change.”

Liberty also stated, “One way of looking at a company’s culture is to see it as the set of assumptions that prevails in an organization. Many of CECONY’s assumptions are constructive and supportive of its public service obligations. A number, however, create barriers to change:

- Defensiveness
- Unrealistic self-assessment
- Inability to accept problems
- Unwillingness to consider alternate options
- A willingness to ‘go along to get along’
- A belief that critics ‘don’t understand us.’”

**Regulatory Barriers:**
Liberty stated, “...Regulatory oversight that overlaps with the day-to-day management of the Company is a strong indicator that something is wrong, and correction must start in New York City, not in Albany. Company leadership needs to recognize that it must take the steps needed to regain confidence, lest it cede control to the regulator, in which case the system will not work in the long-term.”

Liberty also stated, “Our intention is to discuss this barrier in a “no fault” way. Searches for blame are not searches for change. As with all the barriers, there are logical reasons for its existence. A big reason here has been the Company’s inability to articulate a long-term vision for the system which has led to a lack of credibility and lack of trust. In turn, the degree of regulatory oversight, including frequent rate cases and line-item veto of proposed work, precludes effective long-term planning by the Company.”
Financial Barriers:
Liberty stated, “...It is in the financial barrier that we see the beginnings of a critical issue that may grow over time. It is here that we see the tangible results that current trends could eventually produce – a future inability to align infrastructure needs, rates, and return. To remain sustainable in an era of aging infrastructure, heightened service-level expectations, fundamentally different societal and business views of risk, and the resulting, vast expenditure requirements, CECONY simply must gain and retain public and regulator confidence that it is providing an adequate level of service and protecting public health and safety at the lowest necessary cost. Absent the CECONY credibility it takes to produce that confidence, maintaining this balance as we look out into the future must be seen as insufficiently certain.”

Liberty also stated, “If the balance cannot be maintained, it is difficult to see (if we look well out into the future) how CECONY can retain the health to remain a viable option for effectively meeting public service needs at reasonable cost.”

Environmental Barriers:
Liberty stated, “The demands on CECONY by any measure are comparatively very high. Public pressure, customer expectations, regulatory control, and media attention make the Company exceptional when compared to the typical utility. The financial and human consequences of performance failures are also much greater. As CECONY leadership has acknowledged, being average is just not good enough. These pressures influence day-to-day decisions and add a dimension that greatly complicates the management of the business, while naturally contributing to the defensiveness mentioned above.”

Liberty also stated, “CECONY is held to a much higher standard, and few would disagree that a higher standard is indeed appropriate. That is simply part of the bargain; i.e., the price that comes with serving one of the world’s most critical electric systems and most demanding stakeholders.”

Approach to the Barriers
The audit report did not include specific recommendations or requirements to address these barriers; instead, Liberty recommended that Con Edison and the PSC work together to develop and adopt a mutually beneficial implementation plan to break down the barriers. A joint effort to address the barriers was launched by the Chairman of the PSC and Con Edison’s Chairman and Chief Executive Officer. This joint effort continues with direct involvement of Con Edison Senior Executives and senior PSC Staff members.
Since the 92 recommendations are related to the barriers, we have been addressing each of these recommendations and barriers in an integrated manner and in the context of improving business processes and operational efficiency for the benefit of customers. As shown in Figure 2, our implementation approach was a bottom-up and top-down strategy – implementation of the 92 recommendations was from the bottom-up while we addressed the cultural, regulatory, financial, and environmental challenges from the top-down. We are committed to making cultural changes, and to sustaining the benefits of our implementation plan. Cultural changes were at the core of the barriers in many ways, and our work in this area will allow the Company to more effectively address environmental, financial and regulatory barriers.
III. Strategic Response to the Management Audit

Board Engagement
The Board of Trustees has taken an active oversight role in response to the Management Audit. The Board and its committees have reviewed the substance of the findings of the entire Management Audit, and discussed at length with management its proposed implementation of its responses to the Audit’s recommendations. The Board has overseen management’s responses to the Audit recommendations, discussed key implementation matters and reviewed with management the status of the implementation of responses to the Audit.

In June 2009, Con Edison’s CEO led a Board discussion about the Company’s response to the Management Audit, and during that month’s Board meeting, senior officers reviewed and discussed the draft Audit Report with the Board. In July 2009, Liberty discussed its findings, audit recommendations, and the barriers with the Board. The day after this presentation, the CEO discussed with the Board the Company’s ongoing response to the Management Audit. Additionally, in July 2009, the CEO outlined to the Board the Company’s plan, and the Company’s actions in progress, to address the Audit recommendations. The CEO reviewed the key goals of the Company’s implementation plan, including the development and execution of a strategy to support the Company’s long-term growth, the development and execution of a plan to address the cultural and other barriers that would impede the Company’s success, and the development of a structure to strategically address the Audit recommendations and observations.

The full Board and Board Committees continue to provide direction and guidance on team progress during the implementation process. Through September 20, 2012, the Board has discussed audit recommendations at 15 Board meetings and 22 Committee meetings. Topics discussed include Board Committee structure; the role of executive management, the Board and its Committees in response to serious events; cost management; affordability and sustainability; long-range planning; and barriers and cultural change. The work of the barriers team and culture change initiatives have also been discussed at full Board meetings since the start of implementation. Because the audit recommendations are far-reaching and affect virtually all Company operations in one way or another, other agenda topics have also been discussed in the context of audit implementation.

The Board provides implementation guidance through the engagement, discussions and feedback from Board Committees and the full Board. The Chairman of each of these Committees provides reports to the full Board. The Executive Sponsors for the Implementation
Plan provide periodic updates at Board meetings. Each of the 12 implementation teams is working with the Board, and some are receiving direct guidance from specific Committees. Invitations are open to Board members beyond each of those Committees. For example, the Company’s Strategic Long Range Plan is presented to the Planning Committee with the full Board in attendance.

As demonstrated by the active involvement of its Board, beginning with its review of the Company’s plan for addressing Audit findings and recommendations and continuing with its engagement with the implementation teams, Con Edison has been fully committed to the implementation of Audit Report recommendations. The Company’s approach for addressing audit findings and recommendations is discussed in the following sections.

**Structure to Strategically Address the Audit Report’s Findings**

Con Edison established a senior executive team-led structure to evaluate and address each of the barriers and the 92 recommendations. The Audit Report’s recommendations have been grouped and assigned to one of 12 teams comprised of subject matter experts. Each team is sponsored by one or more senior executives charged with oversight of the team’s implementation of recommendations. The executive sponsors provide senior-level oversight for each issue being addressed, and provide updates to and request feedback from the Board. Company officers were assigned as liaisons to each of the Board Committees to facilitate additional input and guidance. An executive-led team was established to address the barriers.

Con Edison’s Corporate Leadership Team (CLT), comprised of the Company’s senior executives, has been engaged in ongoing support of recommendation implementation. The CLT continues to champion the imperative for change, facilitate long range planning, integrate work of the various teams, set standards for deliverables, and establish success metrics. The CLT also took on the responsibility for driving our cultural change.

The overall executive oversight of the Audit recommendation implementation is assigned to two senior officers, the Senior Vice President of Enterprise Shared Services and the Senior Vice President of Business Shared Services, who ensure that recommendations are addressed in an integrated and holistic manner to achieve operating efficiency for the benefit of customers. They oversee and coordinate execution of all implementation activities under the AIP, which addresses the barriers, recommendations, planning process, operating efficiency as well as outreach and communication. These executives interact directly with the CEO and the Board.
The strategic structure for audit implementation is shown in Figure 3:

This comprehensive structure focused implementation for each recommendation on response to the spirit of the specific recommendation, its relation to its recommendation team’s overall goals, and an evaluation of how actions taken to address that recommendation could positively affect any or all of the barriers that Con Edison faces. The implementation process is a company-wide “call for action” that fully engages all employees.

Continuous feedback and direct line-of-sight from senior management to those performing the actual work to complete recommendation implementation has been a key factor in making sure that the recommendations are addressed in a responsive, timely and strategic manner.

**Guiding Principles for Implementation**

To support the core objectives of openness and continued diligence, senior management developed “Guiding Principles” to give direction for implementation. As with the Audit itself, the goal of these principles was to facilitate open and timely communication and action. Each of the 92 recommendations was viewed both individually and in relation to the other
Each recommendation was evaluated with an eye towards addressing not only Liberty’s conclusions, but a determination of how actions could be expanded or improved to further benefit customers. Some of these Guiding Principles include:

**Put aside traditional thinking**
A third-party evaluation provided an external look at processes and practices that may have been taken for granted as just “the way we’ve always done it.” Liberty provided a valuable viewpoint in this respect. We asked all participants entering the process to be open minded about possibilities and opportunities. Throughout the implementation, we asked them to challenge traditional ways and be open to consider new approaches and new opportunities. In many cases, it meant benchmarking with other companies facing similar challenges to learn how we could implement a better or the best solution. Each recommendation was viewed as an opportunity to initiate change.

**Think about what initiated the recommendation; identify the root cause**
Instead of responding narrowly to the recommendation at hand, we took a broader view of the recommendation and looked for the root cause of the underlying issue. We looked beyond the recommendation to learn what other issues could be identified, and how we could address those as well through implementation. We also examined impacts relating to the Company’s internal culture and external operating environment. We wanted to go beyond answering a particular recommendation, and make a positive and sustainable impact on our business practices.

**Examine if the recommendation is purely tactical, or if it is strategic in nature**
Recommendation scope varied from clear changes in practices to shifts in business management philosophy, and at times even the “small” practice changes required greater shifts in thinking. For this reason, it was important to view each recommendation in terms of the overall audit themes and in terms of mitigating barriers.

**Look beyond the specific finding**
Each individual conclusion and recommendation provided a part of what needs to be done and each must be understood in the context of all the recommendations. We asked participants in the process to think about how their recommendations related to the greater themes
introduced in that section and chapter of the Audit Report, and, just as importantly, how their efforts positively mitigated the barriers.

*Quantify the costs and benefits of implementation*

Each team was charged with identifying the costs and benefits of recommendation implementation. To provide a consistent approach to quantification, we conducted a cost-benefit training session for our team leads and executive sponsors. Formalizing this process has highlighted cost-benefit evaluation in the decision making process. It requires the participants to justify their proposals by showing metrics and tangible results, thereby reinforcing accountability for cost consciousness.

Milestones for implementation cost benefit completion were defined in October 2009, and we have been monitoring the results closely. Beyond measurable dollar savings, we also consider benefits from risk reduction, increased transparency, process improvement, impacts on reliability, and how actions support a cultural change.

*Work as a team*

While implementation efforts were organized by 12 different teams, each team maintained contact with the others to ensure an integrated approach. Our executive sponsors make frequent presentations to the Company’s top managers and CEO, and we employ a dedicated Audit Support Team to facilitate overall implementation. All of these efforts ensure that we are responding in a holistic and consistent manner.

*Commit to change*

Many of the recommendation implementation initiatives represent fundamental changes to the way we work. While we believe that while each change we make is for the better, we recognize that to be truly successful each must be sustainable for the long term. For this reason, we have sought to embed these changes into procedure and formal practice. Thus, for example, we have integrated cost management into the definitions of our Way We Work principles; we have implemented longer-term stretch goals for OSHA incidence rate performance; and we have modified corporate instructions regarding transmission planning criteria.
IV. Update for the Year

In the year since our second Annual Report and Update, we have completed one additional recommendation, for a cumulative total of 91 completed. Through implementation of this recommendation we have improved our long range planning with the development of a Steam Long Range Plan (SLRP), this effort is summarized below. We also continued work on the one outstanding recommendation, implementation of a new electric work management system.

Full completion details for all completed recommendations are provided in Appendix C along with updated information for the one outstanding recommendation.

Although largely complete with implementation, our work related to the audit recommendations carries on through the continuous improvement of our business practices. For example, we continue to improve our asset management strategies as part of our long range planning initiatives and continue to integrate new and innovative planning and design strategies to reduce our capital investments and to improve the use of our existing assets. These and other efforts will continue to provide benefits for our customers and provide for the long term sustainability of the Company.

Steam Long Range Planning
We continue to improve our planning processes. We have developed a Steam Long Range Plan (SLRP) to identify and understand the issues and challenges impacting the steam system over the long-term along with a long range business strategy to maintain the viability and sustainability of the Steam business. The goal of the Plan is to help direct the Company in balancing supply capacity with anticipated customer demand, while maintaining the competitive value of steam for the steam customer.

The SLRP addresses the business strategy for the Steam system for the next 20 years as well as the future investments on production and distribution, while recognizing that customers play a critical role in driving the requirements. As part of the development of the SLRP, the transmission and distribution systems were evaluated and initiatives were developed with the purpose of addressing system needs, deferring or minimizing the investment requirements on the system, increasing asset utilization, and improving overall performance. Long term programs for maintenance and operations, including renewal, removal or addition of assets, were developed. Major distribution investments the Company will undertake to meet the Plan are as follows:
• Continue expansion of existing remote monitoring program in flood prone locations and trap monitoring.
• Extend distribution system monitoring and Research and Development (R&D) initiatives on water hammer to continue enhancing employee and public safety.
• Implement a smart-grid approach for Steam that includes additional monitoring of the network and the expansion of advanced metering to allow for demand response (DR) programs. This would also provide better customer usage data which may be used to improve conservation program efforts and load shedding capability.
• Establish an asset renewal program aimed at replacing anchors, valves, manhole covers and other critical pieces of the distribution system.
• Increase operational efficiency by incorporating benefits from smart grid, asset renewal, R&D and other initiatives into process improvements and workforce management.

We developed three demand forecast scenarios representing the high, low, and plan cases. Each forecast scenario considers historical customer growth and departure patterns related to building renovations and new construction; the possibility of additional load from oil to steam conversions driven by potential regulatory changes; load loss from the growth in customer sited and government incented combined heat and power (CHP) projects; and the influence on demand and sales of customer implemented energy efficiency measures. Under the Plan case, aggregate customer load is projected to be relatively flat over the 20 year period. The Plan case accepted a level of maturity in the steam service market territory in terms of growth potential and efficiency improvement impact.

During the development of the Steam Long Range Plan, we met with a representative group of stakeholders, the New York Department of Public Service Staff, and the New York Energy Policy Task Force. In the future, we will continue to have discussions with key stakeholders about our plans. Current customer feedback was considered and incorporated in the Plan.

We have communicated our Steam Long Range Plan internally and to external stakeholders, and we have posted our SLRP and its supporting documents on Con Edison’s corporate website (www.coned.com/publicissues).

We will continue to monitor signposts for changes that affect our long range plans and will update the plans to adjust accordingly.
V. Continuing Cultural Transformation

The Company is continuing on its path to cultural transformation. In our third year, we remain committed to making cultural changes by consistently seeking opportunities to capitalize on our strengths and actively addressing our challenges. Our cultural transformation efforts continue to be led by our Corporate Leadership Team (CLT). CLT continues to dedicate a full day each month to culture change session workshops and meets regularly with the culture subject matter expert, Dr. Steve Simon.

Our three cultural change imperatives – enhance customer and other external relationships; engender openness, fairness, and trust; and enhance cost management consciousness are at the pinnacle of many of our projects, initiatives, and activities. We continue to integrate these cultural imperatives into our cultural and business activities.

Efforts to integrate the cultural imperatives as key values in our work culture included engaging in a company-wide communication campaign to promote the recently revised WWW principles, which now incorporates the three cultural imperatives of “cost consciousness,” “openness, fairness and trust” and “customer/shareholder relations”. As part of the collaboration between the WWW Steering Committee and Public Affairs, the Company engaged in a campaign to increase employee awareness about the newly updated WWW principles. The communication effort consisted of a company-wide poster board campaign incorporating the three cultural imperatives as part of the WWW principles and demonstrating how we can integrate the WWW principles into our work.

To help navigate and facilitate the changes we are making to our culture, a new Change Management Team was created. The Team’s purpose is to develop a plan to help organizations manage change in a consistent and effective manner. The Team’s work involves developing procedures to help supervisors guide employees to make sustainable change – be it change related to the cultural imperatives or other change initiatives. This initiative highlights important steps that we are taking to ensure long term sustainability of our cultural change effort.

We continue to see evidence of cultural transformation throughout the Company. In September 2011, we conducted the second company-wide confidential Voice of the Employee survey administered by an independent research company, Towers Watson. Employees were given the opportunity to share their views on significant matters at the Company, including their job, work environment, career development, and leadership. The survey assessed
employee engagement and measured the Company’s results against various benchmarks, including our 2009 survey results.

This survey also included several questions about the Company’s corporate culture change initiative. Most employees believe that the Company is committed to improving the culture and report personally seeing positive efforts to improve in the areas of safety, cost consciousness, and enhancing our relationships with external stakeholders.

The results identified several strengths. Employees recognize the Company’s commitment to operating safely, feel strong connections to the Company, and understand how the work they do contributes to the Company’s overall success. Employees are also confident about the future of the company and believe senior management is taking steps to promote the company’s long-term success. Employee engagement continues to be strong among all employees. While some employees reported seeing the Company’s efforts to create a more open and trusting environment, most believe that we still have more work to do. We will continue to strive to be open, fair, trusted and trusting, in all our relationships, both externally and internally.

We continue to make progress on the cost management and enhance external relationships imperatives. We are following our plan to improve the engendering openness, fairness and trust imperative. We know that making progress with respect to this challenging imperative can significantly help to accelerate our culture transformation. We will continue to target ways to better understand how to assess the success of these efforts.

We plan to conduct a pulse survey in the fourth quarter of 2013. A pulse survey can provide additional information regarding the specific actions taken as a result of the 2011 Voice of the Employee survey and determines if progress is being made on targeted action plans. A pulse survey has a limited number of questions and is a cost effective way to continually monitor progress. This survey will be designed to provide feedback and insight regarding the impact of several key initiatives on cultural transformation, Total Rewards (employment benefits), 2012 contract negotiations, Project One, the Work Management system and health care program.

The Company’s efforts continue to focus on identifying observable behaviors, recognizing how perceptions become realities and how culture change can only happen as assumptions, mindsets, and ultimately behaviors change. Changing culture is also about cascading new behaviors down throughout the Company. This change will take time because behaviors are well-rooted but we will be diligent and persistent in working to bring about this change.
The next sections describe some examples of culture changes organized within the three imperatives.

**Enhance Customer and Other Relationships**
Each employee is responsible for continually working to find ways to enhance our relationships and deliver a positive experience for our customers and other stakeholders each and every time they interact with us. We recognize the substantial interest that customers and other external stakeholders have in different aspects of our business, and we will affirmatively engage our customers and external stakeholders in various aspects of our business.

*Long Range Planning Outreach*
We incorporated customer and stakeholder input into our integrated long range plan, and continue our outreach efforts to discuss the plan with our stakeholders, internal and external, to communicate the results of our efforts, and to obtain their input. Our long range plan documents and communicates the Company’s direction to our employees, our customers, our shareholders, our regulators and other key stakeholders. It provides a means to discuss and understand future directions, goals and objectives, challenges and opportunities, and to understand potential future customer impacts.

*Oil to Gas Conversion Team*
New York City implemented boiler-fuel regulations in April 2011 to phase out the use of heavy heating oils. The regulation will eliminate use of No. 6 oil by 2015 and No. 4 oil by 2030. As a result of the regulation, we have seen an increase in customers converting their heating fuel from oil to gas. Recognizing that the influx of requests would bring new customer service challenges, the Company established a new department dedicated to gas conversions.

We have streamlined the process to make it easier and faster for customers to convert. A Web page ([www.conEd.com/gasconversions](http://www.conEd.com/gasconversions)) was developed, creating a one-stop resource for customers looking to convert from oil to gas. Visitors can find information on natural gas, become familiar with the process for converting – including a timeline for gas service installation, discover the financial benefits of converting by using the savings calculator, obtain answers to frequently asked questions, and obtain direct contact information for the Gas Customer Solutions Team.
We are taking a strategic approach to marketing by targeting customers close to gas mains so that we can minimize capital construction costs for our customers. We have also “clustered” customers together to take advantage of the economies of scale and efficiently add them to the system while minimizing construction disruption to the neighborhoods by “building once.” This allows the Company to save money on excavation and paving costs while minimizing noise and reducing our presence in the street.

We continue to inform and educate the public on the benefits of converting (and clustering in particular) with activities such as mailings, town hall meetings, and presentations to real estate associations, building management organizations, and contractor and plumber associations. In addition, we are working closely with the New York City Mayor’s office, participating in the Clean Heat Task Force and meeting regularly with the City’s marketing contractor, ICF.

Since the regulation was implemented in April 2011, we have received almost 4300 requests (as of July 2012) and have installed almost 500 services (as of July 2012).

**Powering Effective Use of Social & Digital Media**

Con Edison recognized early on the importance of incorporating the use of new technology into its traditional communications activities. One of the key successes to embracing social and digital media to inform and engage its stakeholders, especially during Hurricane Irene, was the ability of Public Affairs representatives to integrate seamlessly into the Company’s emergency command center during events.

The Company’s social media platforms, Facebook, Twitter, and YouTube, are used to provide customers, media, elected officials and members of the community with an alternative way to obtain important Con Edison information such as outage information, estimated restoration times, safety tips, energy efficiency tips and other company news.

Con Edison uses emails with links to online videos to alert customers to important information such as what to do if they lose power during a storm. Nearly one million customers have opted to provide Con Edison their email address.

Social and digital platforms are also helping the Company’s media relations team to maximize efficient use of technology - parallel to the explosive growth of the citizen journalist in the media capital of the world.
The Company’s social media efforts during Hurricane Irene earned awards from two public relations organizations - Bulldog Reporter and Ragan Communications. Con Edison primarily used two social media platforms during Irene: Twitter and YouTube. The Company used Twitter to curtail the spread of incorrect information before the arrival of the storm. The Company also produced several videos to illustrate storm preparations, show extensive storm damage and highlight restoration efforts. Both platforms created greater public understanding of the Company’s restoration efforts.

**Smart Grid Demonstration Projects**

Community outreach, stakeholder notification and coordination with local governmental agencies have been a major part of our smart grid program. Significant portions of the smart grid initiative required local governmental agency approval (i.e., installing feeders through Flushing Meadow Park, and installing wireless routers on City-owned streetlights) and we have worked closely with the respective agencies such as the NYC Department of Parks and Recreation, NYC Department of Transportation, and the Public Design Commission to expedite the process. We have also reached out to elected officials and community board officials in communities where smart grid equipment is being installed to inform them of the initiative and the role of the smart grid equipment. Where we are installing equipment such as switches in sidewalks in residential blocks, we are notifying individual residences of the pending work with an explanation of the smart grid initiative.

**Times Square Interference Work**

The City of New York plans to redesign Times Square with a scheduled completion date of December 31, 2013. In order to meet this ambitious schedule, Con Edison developed plans to start working in spring 2012 to remove and/or relocate gas, electric and steam facilities in advance of the City’s project; in the absence of joint bidding, this approach provides the Company with more flexibility to identify cost-effective approaches to complete the needed work. However, the public and private stakeholders who utilize Times Square for special events and other activities were not expecting work to begin until much later in the year. In order to maintain a positive, collaborative relationship with the project’s stakeholders, Con Edison established a comprehensive communication and outreach initiative for its share of the Times Square infrastructure project.

Through collaboration with the City agencies and stakeholders such as the Times Square Alliance, Con Edison has been able to proactively begin work with all three commodities and continuously coordinate around other events and activities in Times Square. For example, we
negotiated to encourage entities such as ABC’s Good Morning America to temporarily relocate further up the block. The Company coordinates with a group of core stakeholders through daily e-mail updates and weekly conference calls. We also provide updates to the public via email and on the Con Edison website (http://www.coned.com/publicissues/times-square-project.asp).

Our plan is to do as much work as possible while the streets are open to minimize returning once the City’s project is complete. Because of this effort, stakeholders are able to plan ahead for their events to ensure that our work does not disrupt their schedules. Con Edison plans to complete a majority of its maintenance/relocation work ahead of the City’s schedule.

**Targeted Demand Side Management Steam AC Incentive**

In the spring of 2012 Con Edison developed an incentive program to encourage customers with steam air-conditioning (AC) in constrained electric networks to remain on the steam system, rather than converting to electric-driven chiller plants. As part of its Targeted Demand Side Management (TDSM) program, Con Edison would offer to subsidize up to 65 percent of the total cost of a new steam chiller for customers that are located in “targeted” electric networks – i.e., networks forecasted to need capital investment due to load growth that is driven in part by customers migrating from steam to electric cooling. By keeping steam AC customers’ peak cooling load off of the electric system, Con Edison can defer major infrastructure upgrades at the area substation level, which helps reduce the need for rate increases for electric customers.

Con Edison presented its incentive program concept to PSC Staff on April 25, 2012, and agreed to have further discussions to resolve Staff’s questions about design and implementation of the incentive. Reflecting the cultural imperative of enhancing external relationships, it was important for Con Edison’s team to work with Staff on this proposal to optimize the synergy between electric and steam system resulting in lower costs to electric customers. To demonstrate that the steam AC incentive is a cost-effective means of deferring infrastructure investments, Con Edison went to great lengths to develop and refine a model that applied Staff’s Total Resource Cost (TRC) standard to steam chillers. Through multiple discussions, the Con Edison project team worked with Staff to refine the model and affirm that the calculations were accurate. Ultimately Staff agreed that the steam AC incentive is a cost-effective, reliable means of achieving long-term load relief for the benefit of electric customers. The steam AC incentive will be available starting in September 2012, and will be officially announced at Con Edison’s annual Steam Customer Seminar on October 10, 2012.
Engender Openness, Fairness, and Trust
We strive to be open, fair, trusted and trusting, in all our relationships, both externally and internally. We recognize that trust must be earned. We are taking steps to be more open with our external stakeholders and employees in an effort to earn that trust.

Performance Management
Utilizing the iceberg and cycles of trust culture tools, the corporate leadership team completed a comprehensive review of the current performance management system and associated pros and cons. An external performance management subject matter expert, Dick Grote, was engaged to provide guidance. In addition, best practices were benchmarked. The result was a revamped performance management system that provides for timely and accurate feedback, goal setting, improvement plans and rating distribution guidelines. We implemented the enhanced performance management system in April of this year as a means to move to a high performance culture.

Total Rewards
Utilizing culture tools and outside consultant expertise, benchmarking, and employee surveys, the Company redesigned the structure of compensation and benefits for management employees to meet several guiding principles:

- Develop a Total Rewards program that is cost effective and competitive with the median of peer group companies
- Attract and retain employees with programs that are valued and understood by the workforce
- Incent the right behaviors by providing programs that recognize and reward high performance
- Offer programs that address financial risk and volatility
- Design programs that consider expectations of our external stakeholders - customer, regulators, and shareholders
- Provide consistent programs across CEI companies as appropriate, which will help promote career opportunities
- Encourage employee engagement and shared responsibility
Employee input, benchmarking our current program against a peer group of utilities and New York metro companies, as well as extensive review of alternative designs, revealed the following:

- Time-off could be structured in a more flexible way
- Variable Pay is below market
- Retirement benefits, including the Thrift Savings 401 (K), were below market for the Cash Balance Pension Plan/CEB employees and above market for Final Average Pay (FAP) and Career Average Pay (CAP)
- Cost and benefit for retiree medical is above market
- Sick Pay/Disability benefits are above market
- Health care costs are above market and programs didn’t reflect best practices

As a result, changes in our Total Rewards package for management employees are being implemented beginning January 1, 2013. Satisfaction and understanding of Total Rewards can translate into greater employee engagement and retention. These are important changes aimed to reflect best industry practices.

**Contract Negotiations**

Contract negotiations with Local 1-2 began in April to address the expiration of the collective bargaining contract on June 30, 2012. In alignment with the cultural imperatives, a formal employee communication plan was developed which included sharing the guiding principles for negotiations:

- Negotiate a fair and equitable contract that honors the value of employees and the long-term success of the Company
- Consider the needs of all stakeholders-employees, customer, regulators and shareholders
- Recognize that shared interest is an area of focus for progress and proposals
- Communicate openly and respectfully and demonstrate empathy for the views of the Union
- Achieve a final contract package that is cost effective and competitive, maintains the Company’s ability to attract and retain the right people, and considers the long term sustainability of the business.
Also, during the labor negotiations, we produced over 95 “Negotiation Updates” for management employees to describe the negotiation process and progress, contingency preparedness and answer frequently asked questions. This was a first in terms of a comprehensive contingency communication plan.

The lockout and work stoppage was rooted in the Company’s commitment to customer service. The union refused management’s offer at the expiration of the collective bargaining contract to extend the current contract for two weeks while talks continued, or to continue to negotiate if both sides agreed to give each other seven days’ notice of a work stoppage. The Company also offered to allow workers to return to work in return for a commitment to a 72-hour notice of a work stoppage. The union chose not to accept this offer. Without a no-strike/no-lockout agreement or a new contract, the Company had no choice but to lock-out bargaining unit employees in order to maintain safe and reliable energy services to our customers.

The new contract addressed key priorities for the Company, primarily in the area of pensions and health care. With respect to pensions, the Company achieved a cash balance pension plan for new hires. While this achievement does not have immediate savings, it addresses long term costs and sustainability by providing a path to managing future employee retirement costs. In areas of health care, the Company achieved the ability to offer additional flexibility programs that will allow employees more choices and control over their cost, and as a result, can also help to lower the Company’s costs. Rising health care costs continue to be a challenge for the Company as it is for other businesses across the nation.

**Vice President of Business Ethics and Compliance**

We have recently created a new position in the Company, the vice president of Business Ethics and Compliance, which is supported by staff members in the Business Ethics and Compliance Organization. The creation of this position further promotes our commitment to an open, trusting and fair corporate culture. The organization under this position is responsible for the Company’s Standards of Business Conduct, coordinating the Company’s Business Ethics and FERC compliance training and communication programs, coordinating and issuing of Corporate Policy Statements and Corporate Instructions and conducting Business Conduct Investigations.

**Management Conference on Openness, Fairness and Trust**

Customer Operations held a one-day conference for all Customer Operations management employees in late May 2012. It continued the mission of the 2011 management conference at which Customer Operations management was trained on how to be Positive Change Agents
(PCAs). This year’s conference focused on advancing openness, fairness and trust in our role as leaders. The mission of the day was to inspire commitment to openness, fairness and trust and to cultivate behaviors that create positive, productive, professional relationships where people are engaged in the business. Customer Operations management explored the components of openness, fairness and trust. The relationship between openness, fairness and trust was explored within the context of relationships with one another and how communication affects the level of openness, fairness and trust.

Participants identified behaviors that build openness, fairness and trust and identified the top behaviors important to them and Customer Operations. In turn, they validated their trust behavior list with an expert in the field, Stephen M. R. Covey who published the “13 Behaviors of a High Trust Leader”. Participants learned to recognize what gets in the way of trust and to work around these impediments. They were reminded of their leadership role and the criticality of being aware of the shadow they cast as leaders through actions, inactions, words, non-verbal signals, etc. They learned the importance of being intentional and conscious and giving others opportunities by extending trust. Lastly, each management employee made a personal commitment to practice a behavior or behaviors to make him or her more effective in advancing openness, fairness and trust.

Cost Management Consciousness
We are working to create a “culture of cost excellence” in which we all seek and accept the responsibility that everyone must manage cost. We have taken steps to increase the visibility of cost awareness, enhance our existing financial processes, tie cost management into employee performance management and improve performance in all areas of the Company.

Vice President of Business Finance and Consolidation of Planning, Budgeting and Forecasting
The creation of the Vice President of Business Finance position supports our culture of cost excellence. With the creation of this position, we have begun to consolidate all of our financial planning, budgeting, and forecasting functions under this one organization. The primary responsibility of the organization will be to oversee financial planning, budgeting, reporting, and financial analysis for the Company. The new organization will help the Company enhance the development of annual and five-year capital and operating business plans, determine enterprise risk expenditures, monitor business performance during the year, quantify expenditure trends, set standards for business analysis, and develop forecasts. This
organization will further integrate these functions within Con Edison creating greater alignment between corporate plans and financial performance.

*Project One*

Project One is a new integrated finance and supply chain system for the Company. Implementation began in the 4th quarter of 2009, and the system was fully deployed in July 2012. The new system replaces 61 existing software systems, which together represented about 15% of the Company’s application software. Through the implementation of Project One, we have enhanced processes used by employees to record financial transactions and analyze data, purchase materials and services and manage inventory, develop business plans and budgets, and report financial and purchasing data.

The implementation of Project One will improve business information and analytical capabilities to facilitate faster access to information for better cost control and decision making, reduce administrative risks, enable employees to have consistent, efficient, and standardized business processes, and add transparency to project spending, materials and services ordering, and inventory management. In addition to improving finance and supply chain processes in the Company, Project One is a major facilitator in changing Con Edison’s culture through enhanced cost management practices. The new system will support a process that will enable us to do business cost analysis and forecasting effectively, efficiently, and productively with more detail and longer length of financial forecasts and budgets. Better analytics and reporting will enable the Company to assess the health of its infrastructure and capital equipment to support better long range planning.

*Performance Management*

In 2012, we also kept our commitment to ensure deep and sustainable cultural change related to cost consciousness, by embedding “cost consciousness” and “cost management” categories into our newly revised performance management system and process. Revisions to performance management include adding a new goal-setting section to the performance review form, which is comprised of goals related to managing costs. By setting these imperatives as goals for employees, we can measure alignment of employee performance with the goals of the Company. By establishing clear and measurable goals, along with consistent performance tracking, we can enhance our culture of planning and cost control.
We continue to implement a new work management system (WMS) within our Electric Operations organization. This project represents as much a technical challenge as it does a cultural one. This project establishes a standardized, organization-wide change in mindset and cultivates the discipline needed to follow a new process for work prioritization, distribution, execution, and reporting. This will result in increased productivity and cost savings in three main areas:

- Field crews – Will increase scheduling effectiveness, managing of prerequisites, and supervisor engagement
- Clerical – Mobile application deployment to field crews will reduce manual back-office close out and administrative activities and will standardize and centralize clerical type work.
- Engineering – Will standardize the work initiation and design process, allow for the improved management of designer workload, and increase the design and estimate accuracy through compatible unit development.

Gas Operations started an initiative to expand the use of trenchless main replacement methods to help reduce construction costs. In 2011, we managed this initiative by assigning a dedicated engineering supervisor and were successful in completing 6,000 feet of main replacement at a unit cost reduction of $100 per foot over standard direct burial methods. In 2012 we transferred these responsibilities to field engineers, and to date we have replaced more than 5,000 feet using trenchless technology.

During the 2013 budget planning process, each organization was asked to identify productivity and efficiency improvements within their operation and the associated savings. The identified initiatives included process improvements, technology enhancements, procurement decisions and better resource management.

Some examples of the cost management initiatives identified in our business plans are:
- Substation Operations and Construction continue to utilize lean work management techniques to reduce costs associated with consumable items with estimated savings of approximately $1 million.
- Steam Operations expects approximately $1 million in savings due to a shift to predictive maintenance cycles for specific assets.
- Corporate Environmental Health and Safety is using more in-house resources to conduct fit test training versus using contractors, yielding an estimated annual savings of $150K.
- Facilities and Purchasing teamed up to procure alternative, environmentally benign cleaning products replacing existing, less benign and more expensive cleaning products, yielding an estimated annual savings of $100K.
- In Customer Operations, the processing of gas meter orders has been automated resulting in an efficiency savings equivalent to two full time positions in the Meter Action Group.

These examples of cost saving initiatives being implemented throughout the Company demonstrate a greater focus on cost management by our employees in many areas of our business. As we continue to enhance cost management practices and a cost conscious culture, we expect our employees to continue to identify opportunities to improve efficiency, increase productivity, and mitigate costs in our business.
VI. Addressing the Barriers

Within the Audit Report, Liberty introduced four “barriers” as root causes of its recommendations and as self-perpetuating challenges that threaten the long term sustainability and success of Con Edison. Liberty defined these barriers as cultural, regulatory, environmental, and financial, and recommended that Con Edison work with the PSC and Staff to jointly mitigate these barriers. Liberty specifically did not include recommendations around these barriers, and suggested that they could only be addressed through buy-in from all parties and a jointly managed and directed action plan. Con Edison responded by working collaboratively with the PSC and its Staff to address the barriers.

Con Edison took the lead to address the barriers, seeking to understand the issues and make changes where and as appropriate. As part of the process, we established a joint committee with DPS staff to be able to discuss and demonstrate our progress. After a few years of working with DPS Staff to address the barriers, Staff has recognized the successes we had made in terms of the cultural, financial and environmental barriers and we will continue to have discussions with Staff on emerging issues and our further progress on overcoming the barriers.

The cultural barrier is being addressed through our internal cultural transformation efforts that work to better understand our culture, the elements that we need to keep and build on, such as our technical focus and expertise, and the areas that we need to improve upon. While recognizing this transformation is a long term process that will take many years, Staff has indicated that they believe we are on the road to improving our corporate culture and becoming a better Company.

With respect to the financial barrier, we have done a great deal to align the Company’s financial needs, customer rates and the requirements to meet shareholder return. We have made improvements to our budget and financial forecasting processes, implemented new energy efficiency programs, developed new asset optimization processes, incorporated the Enterprise Risk Management process to a greater degree into planning processes, and are implementing a new Electric Work Management System. In addition, the Company’s work on the integrated long range plan and focus on our customers’ total bill have further improved alignment of the Company’s financial needs, customer rates and the requirements to meet shareholder return. Staff has recognized these improvements and has suggested that progress is being made with respect to the financial barrier initially identified by Liberty.
In addressing the environmental barrier, the Company has demonstrated improvement in its engagement of communities, municipalities, government officials, and customers. The Company is making an effort to communicate its vision and to reach customers directly and through the media. We are committed to providing timely and helpful information to our customers to keep them informed and manage expectations. In particular, in times of emergency, our operations will be transparent and open. Being more open with our operations and plans and providing greater information through many different communication vehicles continues to enhance our external relationships, with many stakeholders taking note.

Key to mitigating the Company’s regulatory barriers were the open discussions between the Company and Staff. Meetings continue to be more open, and both parties have been making greater efforts to share information and improve understandings. For example, the Company, in consultation with Staff, reviewed a variety of the Company’s operating practices and programs that are performed in accordance with existing regulatory requirements and identified modifications, which, if made, would address the underlying purposes of the programs and reduce costs. As a result, several of these requirements were modified as it was determined the benefits did not outweigh the costs. Other such issues will continue to be raised in appropriate regulatory processes.

Con Edison maintains a critical focus on the barriers, and embraces the challenges they present to improve the business. Work to address and mitigate the barriers supports the cycle of change as initiated by the Management Audit as well as implementation of each of its recommendations.
VII. Integrated Long Range Planning

In 2011 the Company undertook an effort to forge an integrated long range plan (ILRP), updating much of the information contained in the 2010 individual commodity long range plans. This integrated plan evolves the Company’s planning process beyond the specific recommendations in the management audit as it focused on identifying ‘cross commodity’ opportunities to provide additional benefits to customers and on addressing non-delivery portions of the bill for the service we provide our customers, principally supply costs and taxes and fees. The ILRP was published by the Company for public review in August 2012, and can be found on the Company web page at the following link http://www.coned.com/publicissues/. This section highlights the major findings of the 2012 ILRP.

In the 2010 electric, gas, and steam long range plans, we identified about $4 billion in estimated cost savings and avoidances over the 20-year planning horizon by focusing on ways to reduce our delivery costs. In the ILRP we build on those opportunities by implementing a new framework focused on integration. We applied a common framework to our infrastructure planning process across the three commodities, and utilized long-term forecasts based on a common set of basic data, assumptions, and industry trends. Using this integrated framework, we aim to minimize the investments we must make over the next 20 years. As a result of our integrated planning process, we identified over $6 billion in cost savings, deferrals, and avoidances across the three commodities over the 20-year planning horizon, which is $2 billion greater than the savings and cost avoidance identified in 2010 long range plans.

The ILRP focuses on four key goals: minimizing customer bill impacts (focusing on total customer bill which includes supply, taxes, and fees), improving customer service, maintaining reliability, and meeting environmental goals (i.e., Con Edison, NYS, and NYC environmental goals).

To achieve the first goal of minimizing customer bill impacts, the ILRP addresses three key objectives: minimizing customer energy use, improving our use of existing assets, and reducing all components of our customers’ bills. The first two objectives are aimed at reducing our customers’ delivery costs, which make up approximately one-third of their bills. We aim to reduce delivery costs first by reducing demand, then by using our assets more efficiently to meet that demand. The third objective addresses the remaining components of our customers’ bills—energy supply cost, and taxes and fees.
First, we will help our customers lower their demand and energy consumption. Our efforts to reduce customer peak demand, where applicable, will lower additional infrastructure costs and improve the utilization of our existing utility infrastructure. We are also helping our customers reduce their overall energy use by offering various conservation and energy efficiency programs.

We are working with customers to offer a broader range of energy solutions that considers customer impacts and the optimal use of the three commodities. For example, our energy solutions will consider such options as oil-to-gas conversions and steam air conditioning if beneficial to customers. We will also incorporate customer-sited combined heat and power or other distributed generation resources into our planning processes, provided they have a track record of reliable performance. Cost-effective solutions will be considered where they can provide direct benefits to participating customers, while reducing our system peak demand, and allowing us to defer large capital investments for the benefit of all customers.

Second, we will improve our use of existing assets to reduce capital investment and therefore lower customer costs. With the help of new technologies, systems and processes, we seek to make better use of existing assets with spare capacity, rather than make an additional infrastructure investment. To this end, we rely on refined system modeling and robust cost-benefit analyses for all of our projects so that we can make more informed and cost effective decisions. We are standardizing our work processes through improved project management and work management systems.

Third, we recognize that our customers’ bill includes not only our delivery costs, but also taxes, fees, and wholesale energy costs. We continue to work on behalf of customers to influence energy supply components of the bill. We maintain a strong presence in various regulatory and wholesale market forums, where we advocate for policies and standards that result in fair, competitive customer supply costs, while maintaining reliability and preserving the integrity of the wholesale markets. Similarly, we are pursuing opportunities to lower the taxes and fees portion of our customer bills, in particular focusing on the Public Service Law 18a surcharge, one of the largest fees we are required to collect.

A number of opportunities highlighted in the ILRP are in the process of being implemented by the Company. For example, the ILRP highlighted the potential impact of the migration of customers for steam-powered air conditioning to the electric system for their cooling needs, a driver of growing electric demand in some of Con Edison’s electric networks. As a result of that potential impact, Con Edison has developed an innovative steam air conditioning retention program which will encourage existing steam AC customers to upgrade their end-of-life
equipment to more reliable, higher-efficiency steam AC chillers, which we expect will keep that source of demand from migrating to the electric system for at least 20 years. Another example is the integration of customer owned and operated distributed generation into the Con Edison load forecast. By reflecting the positive impact of reliable DG in the load forecast, Con Edison was able to defer the construction of electric infrastructure. That deferral results in a savings for all of our electric customers.

Our goal is to create synergy whenever it’s applicable. There are however differences among our three commodities that require three different rate structures and three different capital plans. First, the physics of transporting electricity, gas and steam require different physical systems to transport each commodity. These different systems have different requirements for maintenance, expansion and operation. Second, the three systems have overlapping, yet distinct geographic footprints. Third, our customers’ end use for each of the three commodities is different, and customers’ need for integrated solutions varies according to factors such as their energy usage, cost and their willingness to operate complex infrastructure on their premises. Local, state and federal laws and regulations, such as fire department codes, city building codes, and state environmental and utility regulations, also drive how much integration is possible.

We believe our integrated approach will best serve our customers. In addition to posting our long range plans on our internet site, Con Edison engaged in substantial public outreach with stakeholders including local governmental, business and community groups to communicate our 2010 plans. Similarly, we plan to use the 2012 ILRP to provide updates to our stakeholders on the strategic direction of the Company.
VIII. Sustainability

The key goal of our implementation efforts was the development and execution of a strategy for the long-term sustainability of the Company. As an initial step, we provided the framework for sustainability of the actions we took around the individual recommendations.

In last year’s annual report, we discussed in detail our efforts to provide for the sustainability of recommendation implementation actions and improvements. The next section, following up on our sustainability discussion in last year’s report, summarizes how our implementation efforts and improvements are still being carried out throughout the Company. We also introduce any new initiatives that have grown out of our original implementation efforts and provide updates or describe new benefits we have achieved over this past year, either through original actions or continuous improvement efforts. This section is organized by the 12 implementation teams.

Team 1: Electric Long Range Plan

*Developed 20-Year Electric System Long Range Plan*

In December 2010 we published our Electric System Long Range Plan (ESLRP or ELRP). This plan laid out our expectation of customer demand on our electric system for the next 20 years, and described the infrastructure that would be required to safely and reliably accommodate customer demand. We also estimated the costs of the investments required to accommodate this demand, and resulting impacts on our customer bills. This plan was communicated to numerous external stakeholders, and posted with its supporting documents on Con Edison’s corporate website.

In 2012, we have updated and integrated our electric, steam, and gas long range plans into a single Integrated Long Range Plan (ILRP). This effort was part of an ongoing long range planning process to monitor and incorporate the impact of various economic, technological, and public policy issues. This structured and regular reevaluation will support the sustainability of our long range plan as a continuously relevant and viable document.

The ILRP was published by the Company for public review in August, 2012, and can be found on the Company web page at the following link [http://www.coned.com/publicissues/](http://www.coned.com/publicissues/).
**Defined Role of Strategic Planning**

Strategic Planning continues to facilitate corporate direction setting, standardize plan development and integration with the corporate strategy, lead cross functional business integration, and track progress. Strategic Planning served as overseers of the integrated long range planning effort ensuring that our actions across all three commodities we deliver—electric, gas and steam—are consistent, coordinated, and focused on the lowest cost customer energy solutions. Additionally, they continue to seek opportunities for interdisciplinary teams where cross-functional skill and/or cross-organizational interactions may be needed.

Strategic Planning also facilitates quarterly strategy discussions with the Board of Directors to facilitate corporate direction setting. These efforts are a required element of the planning process and reflected in the redefined role and mission of the Strategic Planning group.

**Linkage of Annual Business Plans to Long Range Planning Goals**

Our long range plans continue to guide the development of our annual budgets and shorter term plans. Each year guidance is provided by way of the annual budget guideline memorandum and annual budget book guideline. These documents require linkage between our annual business plans and long range business plans. Annual budgets and shorter term plans are linked to the long range plans through the development of annual business plans. Starting with our 2011 annual business planning and budget process, these annual business plans were standardized with uniform guidelines and templates.

One significant change that was made in this year’s business plans is a discussion of proposed changes to the key performance indicators. In addition to the existing one year key performance indicators that have been in place, each organization has developed three to five key five-year metrics to be used to monitor progress in achieving the organization’s long-term business plan objectives as they relate to the Integrated Long Range Plan.

**Expanded role of Enterprise Risk Management (ERM) Department**

Our efforts to fully integrate risk management into the budget process have been implemented. Annual business plans require an enterprise risk management update and discussion of resources committed to mitigate risks, cost of risks, and quantified dollars in projects devoted to specific risks.
We continue to perform periodic reviews of risk profiles and action plans to determine if progress has been made on risk mitigation efforts. In addition, the Company has adopted a risk bow-tie methodology based on the International Organization for Standardization 31000 international standards. A risk bow-tie methodology identifies the causes and consequences of a particular risk, shown in a bow-tie diagram with the risk in the middle and causes and consequences listed on either side. In a continuous effort to improve monitoring of risks, the ERM department has been facilitating bow-tie risk analysis workshops. By identifying risk causes and consequences, risk owners are able to focus on important and measurable key risk indicators.

_Evaluated Risk and Reliability in Our Electric Network Distribution Systems_
Con Edison measures reliability of its electric network systems by a reliability parameter called Network Reliability Index (NRI), which estimates the frequency at which cascading of feeder failures could be encountered in a network. Guided by the NRI risk indications, efforts at improving network performance continue. The Company is committed to reducing the risk of network shutdown by at least an additional 58% for the top 20 highest risk ranked networks by 2015, while at the same time maintaining current reliability levels for all other networks and controlling associated costs.

Since the close out of this recommendation, we reduced the risk of network shutdown in the top 20 networks by 51% while effectively maintaining existing acceptable risk levels for the remaining networks.

The utilization of the NRI simulation together with a clear horizon of risk reduction expectations continues to make a significant contribution to the acceptance of the Company reliability programs at regulatory levels. Initiatives are under way to develop an analogous NRI metric for the Company’s non-network systems.

_Advanced Energy Efficiency Efforts_
The Company partnered with an outside firm, Global Energy Partners (Global), to conduct an energy efficiency market potential study. The results of the study were used to guide program design of the Company’s EEPS programs and its targeted demand side management (DSM) program. In conjunction with the Global Energy Partners Potential Study, end use measures have been added and updated. Further, an accompanying LoadMap model was developed allowing for more granular scenario development and program analysis.
As a result of updating the LoadMap model, the Company now has the ability to change a number of modeled variables including but not limited to avoided costs, (energy and capacity), discount rates, inflation and measured costs, to better inform program development, market sizing activities and allocation of resources.

The Company remains committed to its targeted DSM program. Improvements in program design and communication have garnered positive results. In 2012 our commercial peak shaving demand response program enrollment grew to 88 MW from 45 MW in 2011.

The Company’s annual evaluation report is submitted to the Public Service Commission by December 1 of each year.

The growth in the use of energy efficiency and other demand management programs is driving more involvement by the Company in how customers operate electric equipment as they conduct their business. Partnering with customers in how they manage their loads allows us to gain insight into the opportunities and challenges our customers face, thus improving our energy efficiency initiatives. In April 2012, the Company commenced deployment of 10,000 modern outlets (“ModLet”) in a pilot program targeting the control of window air conditioning units. This innovative solution is gaining positive feedback from internal and external stakeholders and helping to enhance the energy management conversation at all levels. These 10,000 ModLets are expected to enable the control of 5 MW of coincidental system load.

In addition, we are progressing in the inclusion of demand management as a resource in capital planning. We have successfully demonstrated that we can target demand management to defer needed load relief projects at the secondary level focusing on very specific network needs.

Team 2: Board Leadership

*Revised Board calendar and committee oversight structure*

The Board is now using a revised calendar which provides a framework for a more structured review of short and long-range system needs in advance of annual budgeting, and provides for planning and budget review by the Committees and the Board. The Planning Committee, with the full Board, reviewed the Company’s business strategy in June 2012, in advance of the Board’s review and approval of the budget scheduled for November 2012.

Board Committees continue to review risks that have been identified by the Company’s risk management program relating to the duties and purposes of the respective Committee.
Each committee has been reviewing its dashboard during regularly scheduled committee meetings, and has focused on key operating and performance metrics, as appropriate. This review has provided the committees with the opportunity to address with management the Company’s interim performance vis-à-vis key operating and performance metrics.

The management liaisons to the Board Committees continue to communicate with the Committee Chair of their respective Committees.

Enhanced Board Review for Infrastructure Planning and Budgeting
As required by the Board’s Delegation of Authorities, the Finance Committee reviews all capital projects with an aggregate cost of over $50 million, and the full Board reviews capital projects with an aggregate cost of over $100 million.

In addition, the Finance Committee continues to review their dashboard at every regularly scheduled Committee meeting. The dashboard includes an indicator of "major projects within budget" to allow the Committee to review variations from budget for major projects.

Continued Efforts to Identify Board Candidates with Energy Utility Experience
The external executive search firm is aware of the Board’s interest in identifying board candidates with energy utility experience. To the extent that there is a vacancy on the Board, Management will recommend to the Lead Director / Chair of the Corporate Governance Committee that he encourage the search firm to identify board candidates with energy utility and related experience.

Team 3: Rate and Financial Strategy

Agreed to Multi-Year Rate Plans for Electric, Gas and Steam
The Company considers the adoption of negotiated, multi-year rate plans in the Company’s most recent electric, gas and steam rate cases a significant step toward a longer-term approach to utility ratemaking, an approach that allows the Company a greater opportunity to manage its business from a multi-year perspective.

The Company plans to file electric, gas, and steam base rate cases contemporaneously in November 2012. This approach will further promote cross commodity integration
opportunities identified in the Integrated Long Range Plan and present an opportunity to further consider and address the financial barriers identified in the Audit.

**Team 4: Work Management**

*Optimized Fleet Operations*
Our initial fleet optimization efforts identified over 100 vehicles that were removed from service or redeployed in lieu of purchases, and we have been able to sustain these efforts by formalizing the review of fleet utilization. In 2012, through our efforts to optimize our Company vehicle fleet, we have identified over 180 vehicles which were either removed from service or redeployed in lieu of purchases. These reductions are expected to save approximately $180,000/year in avoided maintenance costs. We continue to work on achieving reductions and reallocation of fleet assets through ongoing initiatives in operating areas to adjust the approach to planning and conducting work.

The vehicle optimization team continues to look for ways to improve vehicle utilization and transportation services. The team was part of the Yard Process Re-engineering Team and initiated efforts of a Vehicle Standardization Team to break down the tendency for individuals and small, functional groups to customize their vehicles. For example, in 2012, Transportation Operations’ Automotive Engineering worked to consolidate vehicle design specifications for Overhead Bucket trucks across regions.

* Improved Vegetation Management*
The consolidation of the distribution line clearance (tree trimming) program has been the foundation for consistent vegetation management work practices and program oversight across operating regions. Operating-area employees responsible for vegetation management have become subject matter experts uniformly trained in line clearance, tree trimming standards established by our internal engineering specification.

*Enhanced Project and Program Management in Electric Operations*
Three project managers and associated staff members are responsible for schedule, cost, and quality performance for various projects and programs across the Manhattan, Bronx/Westchester and Brooklyn/Queens regions. They are integrated into our work process and work hand in hand with our now Centralized Regional/Customer organization and our
Work and Resource Management Organization. This collaboration allows for the alignment of priority of work with resources across the regions.

The Project Management Organization provides sustained benefits in the form of cost and schedule control on Electric Operations projects and programs.

**Implementing Electric Work Management System**
The implementation of the Electric Work Management System is currently in progress with a scheduled completion date of March 2014. The Work and Resource Management department was created to implement and sustain this process.

**Improved Quality Assurance (QA) Performance**
Electric Operations quality assurance inspections are performed by independent central QA group personnel using standard audit protocols. Con Edison’s Quality Assurance Program’s mission is to assure the health and safety of the public and our employees; provide for reliable and economical operation of the Company’s electric system; assure compliance with applicable codes and regulations; and focus Company resources in an effective manner.

Quality Assurance continues to communicate its findings throughout Electric Operations organizations. Detailed monthly reports, corrective action reports and monthly conference calls with all levels of management provide opportunities for lessons learned and corrective action.

**Team 5: Cost Management**

**Instituted a Holistic Approach To Cost Management**
The Company continues to take a comprehensive approach to cost management. We are working to create a “culture of cost excellence” in which we all seek and accept the responsibility that everyone must manage cost. We have taken steps to increase the visibility of cost awareness, enhance our existing financial processes, and improve performance in all areas of the company.

One of our goals in achieving excellence in cost management is to increase the visibility of cost awareness throughout the Company. The Director of Cost Management, a position created as a result of these efforts, continues to highlight the importance of cost management throughout
the Company using various communication measures such as postmaster emails, presentations, seminars, and training courses. The cost management intranet site is a hub for communication of cost management initiatives, cost saving ideas and success stories. Cost management has become a priority as “we plan the work and work the plan”, and is incorporated into the Way We Work principals of the Company. The reinforcement of cost management and cost consciousness is one of our three initial cultural imperatives driving our culture change effort. Through these actions, we have heightened the awareness of cost management across the Company and effectively sustained the momentum created by our original efforts to address cost management.

Additionally this year we have created a Vice President of Business Finance position, to further support our culture of cost excellence. With the creation of this position, we have begun to consolidate all of our financial planning, budgeting, and forecasting functions under this one organization. The primary responsibility of the organization will be to even more comprehensively oversee financial planning, budgeting, reporting, and financial analysis for the Company. The new organization will help the Company enhance the development of annual and five-year capital and operating business plans, determine enterprise risk expenditures, monitor business performance during the year, quantify expenditure trends, set standards for business analysis, and develop forecasts. This organization will further integrate these functions within Con Edison creating greater alignment between corporate plans and financial performance.

A critical aspect for successful cost management is having a supporting foundation of knowledgeable well trained personnel. We have put in place sustainable processes and procedures to enhance the skills and knowledge base of our employees as they relate to cost management.

New position guides for all cost management positions, including more advanced attributes and increased minimum job requirements, are being utilized to develop the job requisitions for the job-posting process, and candidates are screened and interviewed based on the qualifications listed in the new position guides. A cost management career path, which includes recommended training and on-the-job training activities to assist the employee in developing the skills for their current title and to prepare for advancement to the next step in the career path, is being utilized today to support consistent skill set growth and employee development.

Fourteen Cost Management job openings have been posted since November 2011. The requisitions for these job postings were based on the position guides, and the required skills,
competencies and experience levels for each of these 14 job openings were consistent with the cost management career path.

Cost Management training continues to be enhanced and integrated into our training curriculum. Particularly in this past year with the continued implementation of the new Oracle Financial and Supply Chain system, much time and effort has gone into upgrading the financial skills of managers, supervisors and cost management professionals in the utilization of this application. The training effort has been considerable, and the enhanced skills managers, supervisors and cost management professionals have developed will positively impact our cost management techniques well into the future.

Throughout the Company, organizations continue to focus on improving productivity and completing planned units of work in a more efficient manner. Cost management metrics have been integrated into the Key Performance Indicators (KPIs) for each organization. Performance is discussed and highlighted at staff meetings at all levels of the Company.

This year, the budget development guidance memorandum included the introduction of five-year metrics into the budget planning process. Each organization has been asked to identify metrics which tie into the objectives and goals of the Integrated Long Range Plan (ILRP) as part of the budget package to be submitted by each organization.

The Cost Management Sustainability Team, comprised of General Managers and Cost Managers from all areas of the company, continues to act as forum for the communication and exchange of cost management best practices and new ideas. This team’s mission is to sustain our cost management strategy and guiding principles and to deploy cost management methods company-wide.

**Established New Strategic Alignment and Capital Optimization Methodology**

The Company continues to utilize a Strategic Alignment Methodology to help evaluate projects enterprise wide, and make optimized expenditure decisions across operating units utilizing standardized analytical methods and guidelines. The Strategic Alignment Methodology is used to evaluate projects and programs to ensure that funds are efficiently allocated to reduce operating risks and meet strategic objectives. This methodology takes into account the portfolio’s cost, benefits, and weighted strategic value allowing for analysis of all projects and programs as an integrated portfolio. The Business Improvement Services department runs the optimization analysis and provides the strategic value and ranking of the projects and programs within the portfolio to each individual organization’s optimization team.
Optimization teams used the Strategic Alignment Methodology to analyze and select the most strategic projects/programs for the 2013 CECONY Capital Budget. The 2013 budgeting cycle is the fourth year of using this methodology to optimize the CECONY Capital Budget. The Capital Optimization Process is now part of Corporate Instruction CI-610-1, Capital Budget Process.

The Capital Optimization team is expanding the use of the strategic alignment and capital optimization methodology. The team has established a process whereby they review all the active common capital projects every month with regularly scheduled updates to senior management. This provides for consistency and strong governance for the review of common capital projects. We are also using the methodology to analyze and select the most strategic inventions for R&D. Last year, we started working on expanding the Strategic Alignment Methodology to include O&M projects/programs. We will continue to work on O&M program optimization in 2013. We are working on including "risk of execution" into the methodology.

**Improved Resource Planning For Design Personnel**
We continue to see improvements in the quality of designing work performed by outside services. We have achieved these improvements through enhanced oversight and process improvements in the handling of design packages and review of outside contractor work performance.

In addition to the process changes, we started an engineering/design cross training program in 2011 to assist in educating our newer engineers on the details required in an engineering scoping document to enable the designers to produce a more complete and cost effective design package. To date, six sessions were conducted and approximately 30 employees attended this training.

Central Engineering has also embarked on several new initiatives that are aimed at improving productivity, reducing costs and improving quality of work packages. A standardization team was established to further expand the development of standards and templates to improve the efficiency and quality of standard designs for recurring program work. A package reduction team was established to reduce the number of drawings required in a package and reduce the number of copies required for each package. In addition, our procedures for outside services were updated, and improved controls were implemented to enhance the quality and cost management of our work with outside design services.
Through a reduction in budget for outside design services, increased in-house design personnel, and process improvements, we achieved a cost savings of approximately $262,000 annually through increased efficiency and productivity.

**Improved Auditing Practices**

The annual Audit Plan continues to assess the efficiency and effectiveness of Company operations. Annual Audit Plans allocate significant hours to operational efficiency, contractor oversight, and enforcement and compliance with environmental, health and safety procedures.

Efficiency and effectiveness remains an element of all operations-related audits. Auditing works with Operations to identify candidate projects and support processes for assessment. Auditing is making increasing use of data analytics to help identify anomalies and potential indicators of fraud.

Auditing has implemented a guest auditor program to further incorporate operational subject matter expertise into the audit plan.

Auditing also continues to integrate into its annual Audit Plan the risks identified in the Enterprise Risk Management (ERM) Program, and we continue to obtain the input of senior management and the ERM Committee regarding potential audit assignments.

A comprehensive financial reporting risk assessment continues to be performed during the preparation of the annual Audit Plan. This risk assessment is an integral part of the planning process and helps to determine key audits for the Plan. These audits include assessments of potential fraudulent financial reporting, misappropriation of assets, and unauthorized or improper expenditures, all key enterprise risks.

**Improved Program Management in Substation Operations**

Each program category within the Substation Operations (SSO) Capital portfolio continues to have a core team consisting of a Program Manager, Program Engineer, and Financial analyst as well as representatives of the various working groups (Electric Construction, PST, etc.). Team members work together, with the Program Manager taking the primary responsibility to direct team efforts, so work is accomplished as planned.

Program status reviews are now performed at the bi-monthly SSO/CE Issues meeting, as well as with senior management on a quarterly basis. In addition, current working estimates (CWEs)
for each program and each project within a program are prepared and disseminated according to a pre-defined schedule.

Team 6: Load Forecasting

*Improved Forecasting Methods and Organization*
Demand Forecasting has continued efforts to focus on long-term forecasts and improve their inputs and their accuracy. Sensitivity analyses were performed on the electric, gas and steam 20 year forecasts in the fall of 2011 and assisted in the development of the Integrated Long Range Plan. Additionally, demand response forecasts have been integrated with other existing energy efficiency and demand side management programs in the long term electric forecasts. Oil-to-gas conversions are now forecasted separately using a newly developed model that assesses the economic attractiveness of conversion to the customer and feedback on customer gas service requests from our Gas Conversion Group.

As a result of implementation actions, the Demand Forecasting section was split into two sections: one focusing on short-term forecasting (known as Forecasting Services) and one focusing on long-term forecasting, which is still known as Demand Forecasting. This has allowed the forecasting groups to eliminate and streamline certain tasks, freeing up resources for higher value tasks and products, such as developing sensitivities for the Integrated Long Range Plan.

*Realigned and Streamlined Forecasting and Hedging Tasks*
During the 2011 Hedge Plan development process, changes were implemented to the gas hedging approach following our own assessment and input from PSC Staff. Based on additional PSC Staff guidance related to the Public Service Commission’s Order regarding the management of price volatility, the amount of hedging needed for gas customers has been reduced. After assessing the needs of the hedging group in light of other organizational changes, our existing knowledge base, and cross-training opportunities, we identified an opportunity to combine the Gas and Electricity hedging groups under one Manager. This led to the elimination of the vacant position Manager of Gas Hedging & Market Analysis. The new combined group further aligns the hedging activities of electric and gas to allow improved analysis and cross-functional coordination.
Managed and Optimized the Resource Portfolio
The Long Term Electricity and Gas Supply Plans continue to be reviewed on an annual basis and updates made in response to forecasted or markets signals. The 10-year electricity portfolio management plan looks beyond the period of the Three Year Electric Hedge Plan and leverages the 20-year Integrated Long Range Plan, including its supply and energy outlook.

Energy Management has a KPI associated with the Long Term Electricity Supply Plan. This KPI requires that the Long Term Electricity Supply Plan be developed on an annual basis, be presented to upper management for review, and incorporate any comments or suggestions.

Studied and Evaluated Alternative Methods of Forecasting
The Company continues to develop and document sensitivities for long-term peak demand forecasts annually. The consideration of long-term eventualities that may impact forecasts is part of the formal planning process in the update of long-range plan forecasts. They are developed within Demand Forecasting with the assistance of internal and external subject matter experts.

Demand Forecasting continues to examine the inputs to its long term forecast so that any bias can be corrected or eliminated. Additionally, during 2011, when the 2012-2021 forecast was developed, Demand Forecasting expanded its forecasting to include new inputs for demand response and steam to electric air conditioning conversions. These new inputs will be investigated for any bias when the summer ending 2012 actual results are compiled. Any bias or forecasting variance caused by these new inputs will be corrected for future forecasts.

Through benchmarking with other utilities and examining internal data sources, the Company concluded that the utilization of our load research program may enhance our summer experience analysis, but is not practical as a direct input in demand forecasting. We have continued this approach in our post summer analysis. Additionally, this past winter we used our load research program in the post winter analysis for steam peak demand. By comparing the peaks of the 256 largest steam customers, Forecasting Services was able to help validate the peak demand for the steam system. Additionally, this process has been used in season to try to gauge how the forecast is performing.

We continue to study and evaluate other methods as part of our ongoing effort to improve our processes and the accuracy of our forecasts.
Team 7: Gas Main Replacement

Determined Cost-Effective Gas Main Replacement Rate

We are on target to complete the rate case program to replace 150 miles of leak prone pipe from 2011 through year-end 2013. Our plan calls for us to replace 50 miles of leak prone piping in 2012 and another 40 miles in 2013. This requirement is consistent with the study conducted by ZEI Consultants which concluded 50 miles of main is the optimal annual level of gas main replacement.

We have recently taken two steps to validate and improve upon the data and systems used to develop our main replacement strategies. The first effort was to validate the correlation that ZEI made between leak prone pipe replacement and leak repair reduction. The results of a seven year look-back of replacement and repair data confirmed that the ZEI leak repair reduction rate was accurately predicted by the leak prone pipe replacement rate. This validated our application of the ZEI replacement strategy and allowed us to modify the replacement rates within individual operating areas, leading to a significant increase in Westchester replacement targets. The second step has just been initiated and involves working with our vendor, GL Noble Denton, to review and potentially improve the Main Replacement Prioritization program (MRP) that is used to rank the leak prone pipe segments identified for replacement. This effort is currently underway.

Leak prone pipe replacement is a key performance indicator of the Gas Organization, and is included in the corporate tracking system (Capital KPI Modifier Program). These two mechanisms strengthen our commitment to achieve this target while sustaining the recommendation to determine an optimal level of main replacement. The benefit of this replacement schedule is a future reduction in incoming leaks thus mitigating the risk of gas leak related incidents.

Team 8: Gas Capacity Planning

Allowed for More Regular Examination of Gas Supply

Auditing continues to perform regular audits of Gas Procurement functions as incorporated into the annual Audit Plan as a result of the Management Audit. These audits are dedicated to review compliance with corporate policies and procedures associated with procurement decisions and the documentation required for entering into electricity supply contracts.
In addition, the Company continues to conduct annual SOX controls audits as part of its SOX Controls Testing Plan required under Section 404 of the Sarbanes-Oxley Act (SOX) of 2002. These controls address areas of accounting, hedge accounting, confirmations, credit risk, deal authorization and capture, fuel procurement and inventory, gas supply and purchased power, portfolio valuation and reporting and risk management.

*Improved Methods to Forecast Growth in Peak Load*

Demand Forecasting developed a new approach to forecast the CECONY long-term annual firm gas peak demand over a 10-year period. The primary difference between the new approach and the previous approach is the independent development of the natural gas peak demand forecast by Demand Forecasting. This new approach is reflected in the current Gas Peak Day Forecasting Manual.

Demand Forecasting has continued to improve on its natural gas demand forecast methodology. For example, Demand Forecasting has developed and incorporated into its forecasting methodology an oil to gas conversion forecasting tool that assesses the economic attractiveness of conversions to customers. Demand Forecasting has also integrated the natural gas demand forecast with the electric and steam demand forecasts where there are commonalities such as assumptions on combined heat and power (CHP).

*Team 9: Performance Management*

*Created Inventory of Information Sharing and Benchmarking Efforts*

The Company’s Business Improvement Services (BIS) maintains an inventory of information sharing and benchmarking efforts conducted throughout the Company. This inventory is available via an internal website where all Company employees can access and make use of the information. BIS conducts an annual review and update of the benchmarking inventory with current information.

*Reviewed Safety Performance to Identify Areas of Improvements*

In 2010, the Company established a goal to achieve and maintain its OSHA incidence rate at a 1\textsuperscript{st} quartile performance level of 1.5 within five years (2014). The Company continues to make progress toward achieving its 5-year goal. Through 2011 the Company achieved an OSHA incidence rate of 1.92. Through June 2012, the YTD incidence rate is 1.25. Recently, the Company validated that the goal is still representative of 1st quartile performance.
We continue to promote a “Health & Safety Ladder” system to support our goal to achieve and maintain a 1st quartile performance rate of 1.5 within five years. The system helps in achieving our safety goals by promoting frank and continuous dialogue between union and management employees about safety issues.

Organizations have adopted the basic ladder model and meet regularly to raise, discuss, and resolve safety and health concerns at the local level. Although the higher level meetings have yet to gain traction, there are sufficient regular interactions among management and union employees at all levels to meet the base intent of the ladder initiative, which is to keep the dialogue flowing in matters of safety and health, and minimize the potential for collective bargaining concerns to drive discontinuity in such discussions.

We continue to take steps to strengthen our enforcement of contractor compliance with their own safety programs. This effort is aimed at improving not only contractor safety, but Company safety as a whole. Holding contractors to the same standards as our own employees sends a consistent and clear safety message across the entire Company.

To elevate the visibility of contractor safety performance, the Company added a new Key Risk Indicator (KRI) of “Unsatisfactory observations per 100 Contractor Field Observations reports (CFORs).” The KRI status is reviewed each month at the highest levels of management.

During the third quarter of 2011, an environmental, health and safety audit on Recommendation 59 implementation was conducted. The Environmental, Health, and Safety audit report concluded that organizations are following the minimum requirements of the Corporate Environmental, Health and Safety Procedure (CEHSP) A 12.03, EH&S Qualifications for Contractor Procurement, and the Contract Administration Manual (CAM).

During the fourth quarter of 2011, an operational audit on the use of the Contractor Oversight System (COS) was conducted. The Operational Audit concluded that organizations are using the COS to adequately and effectively track/report contractor performance. Auditing also identified further administrative improvement opportunities for certain organizations. These areas included documenting field inspections and contractor evaluations, timely close out of infraction reports and Action Lines, Rules We Live By violations entries in Action Lines, and documenting contractor damages. The associated organizations have developed and continue to act on work plans that address these additional improvement opportunities.
Revised the Management Variable Pay Plan
The Company revised the Management Variable Pay (MVP) plan in order to better align pay and performance. These changes are reflected in an updated Management Variable Pay Plan document which describes the plan and serves to sustain the improvements made as a result of implementation actions. During 2011, plan changes were communicated to all management employees.

In 2011, we reviewed our overall Total Rewards to evaluate whether our program is meeting employee needs, is competitive against a peer group of utilities and New York metro companies, is consistent between CECONY and O&R, reflects best practices in the marketplace, and helps us attract and retain the right people. Total Rewards include employee compensation (base salary and variable pay), retirement and health care benefits, and other valuable benefits (time off, work life balance, and career opportunities) that are advantages to working for the Company. Changes are scheduled for implementation on January 1, 2013.

Enhanced Productivity Analysis
The use of key performance indicators to measure productivity has provided a useful tool for organizations to measure their success in completing tasks and facilitate productivity improvements. The monthly status of productivity KPIs, including any variations, is reported to the organization and the organization’s leadership. The organizational financial managers submit a monthly report to the central Cost Management staff who prepare a composite report for CECONY’s President and his staff. The establishment of productivity measures as KPIs and the regular review process has increased our focus on improving our productivity and reducing costs.

The Company took steps to enhance the functionality of its CECONY Performance Indicator (CPI) system with the development of a trending feature for the CPI dashboard which was completed in January 2011. This enhancement has provided our employees with increased transparency and availability of data, and has been a useful tool for analyzing KPI performance trends and developing projections for future performance.

With the introduction of productivity KPIs and the enhancement of the CPI system, we are now better equipped to identify productivity issues and conduct targeted analysis for the purpose of improving our performance going forward. These improvements helped us achieve our Capital and O&M budget targets in 2011.
**Developed Overtime Policy**
The Overtime Cost Control Policy has created a company-wide standard framework for the management and supervision of overtime resources.

**Improved Resource Planning**
The Company continues to promote and integrate the use of a Virtual Enterprise Modeling (VEMO) model in the human resources planning process. VEMO is a robust workforce planning tool to help managers identify workforce needs in the future, identify gaps between demand and supply for physical workers, and develop resource related strategies for improved long-term resource planning.

We continue to work with organizations in their human resources planning process and are currently refining the five year staffing plan. Utilization of VEMO in projecting attrition in various job families has been useful in developing the hiring needs over the next five years. We continue to work on enhancements to the application to improve the resource planning process.

An HR Guidance Memo that outlines the Company’s guiding philosophy on the use of contractors to obtain the optimal mix of in-house and contract resources continues to be utilized in our resource planning. The HR Guidance Memo establishes requirements for preparing a cost benefit analysis when considering the use of contractor resources. This guidance memo was issued and communicated in 2010 to standardize the decision-making process used by local organizations when making decisions about the use of contractor resources.

**Team 10: Asset Optimization**

**Improved Engineering Operations**
The Company continues to utilize a five step standardized process to create distributed secondary models for all the networks using Poly Voltage Load Flow (PVL) software that was developed under the Secondary Visualization Modeling project. In addition the Company continues to utilize Siemens and CYME software products to enhance its distribution planning analytical capabilities.

Through the standardization of the new five step approach for creating distributed secondary models using PVL software and the adoption of the Siemens and CYME products, we have improved the effectiveness of our distribution modeling. These measures enhance our
engineering operations and asset optimization providing direction for more focused capital spending.

We continue to utilize the results of two studies that addressed the completion of maintenance activities during non peak load times: a study of maintenance activities on the 138 kV systems designed to N-1 standards and a study of maintenance activities on the Company’s auto-loops (including 4kV, 13kV and 27kV). Both studies confirmed the adequacy of existing maintenance procedures during non peak periods to ensure no impact to customers.

The Company’s Transmission Planning Criteria continue to be updated as needed for compliance with our controlling and regulatory authorities, including the New York Independent System Operator (NYISO), New York State Reliability Council (NYSRC), the Northeast Power Coordinating Committee (NPCC), and the North American Electric Reliability Council (NERC). Our Transmission Planning Criteria has been revised in the areas of blackstart capability, automatic fuel switching, and reactive power requirements. The NYISO has completed their review and had no comments.

Engineering remains committed to having a common equipment rating methodology. They continue to meet to discuss any revisions to rating methodology and interact with utility counterparts and with industry standard and regulatory organizations to ensure regulatory compliance and a common understanding and approach to equipment rating issues.

Our new distribution network feeder rating methodology is now implemented through an automated system that works with the Company’s load-flow program, taking temperature, cable configuration, and cable loading inputs directly from that program. This automated method is more efficient than the previous implementation method that involved manually entering the inputs into a standalone cable capacity program then manually transferring the results back into the company’s load flow program.

Engineering is continuously looking to improve upon its equipment ratings methodology, so that equipment is neither underrated, resulting in unnecessary load relief work, nor overrated, resulting in possible equipment overloads during high load periods.

Prioritized Capital Programs
We have implemented process improvements so that individual asset replacement and upgrade decisions are cost effective in comparison to other capital expenditure alternatives. Cost-benefit analyses have been completed for sixteen of twenty two targeted electric
distribution capital programs, and one of these programs was deemed to not provide the anticipated benefits and was terminated during the research stage. Collectively these programs total around $221 million.

The analytic and oversight techniques utilized for capital programs are being extended to the area of O&M expenses and Energy Efficiency programs. In the first case, a refinement of current program O&M budgets for Tree Trimming, Underground Inspections, and CINDE (transformer) Inspections are being investigated to determine if any of those budgets can be re-allocated or contracted to yield better results or comparable impacts at lower expenditure levels. In the case of Energy Efficiency programs analysis, is being undertaken to better quantify the benefit of programs and provide for a potential re-distribution of program funding.

In addition, the Company continues to analyze programs for critical transmission assets for their reliability impact and cost-effectiveness with risk models developed for our transformer and circuit breaker programs. The development of risk models for critical assets created a standard process to monitor all aspects of critical assets to maintain reliability while reducing costs.

**Utilized Innovative Design Approaches**

The development of 3G concepts is now an integral part of the annual capital planning process. Consideration of least-cost 3G alternatives has been widely applied to local distribution system plans in 2011 and 2012, leading to more regular application of innovative designs in the distribution system. Updated least-cost 3G alternatives were included in the 2011 Integrated Long Range Plan, and 3G designs continue to be considered as specified in our engineering operations manual, 3G Review of Capital Programs.

The use of 3G designs has changed the way we design and plan for system improvements and how we operate the system. Engineering is now incorporating 3G design methodology into initial design concepts in contrast to the earlier practice of developing conventional and 3G designs in parallel. We continue to facilitate more wide scale implementation of this approach throughout Engineering.

We continue to evaluate the cost benefit of new 3G designs, and will update existing cost benefit analyses of major substation projects when the service dates are closer.

Another implementation effort aimed at utilizing innovative design approaches is the deployment of SCADA (Supervisory Control and Data Acquisition) controlled sectionalizing switches. These switches reduce the risk of network shutdown. The Company is currently
installing and certifying underground sectionalizing switches for SCADA-ready operation and expects to have about 180 SCADA-ready switches in operation by the end of the first quarter of 2014.

**Team 11: Gas and Steam Planning**

*Enhanced Project and Program Management in Gas and Steam Distribution*

The new Gas Engineering section consisting of one program manager and five project engineers continues to support distribution projects within Gas Operations. As a result of re-examining our main replacement priorities, we have identified the need for increased replacement of leak prone pipe in Westchester. As a result we have increased our staffing level in the Field Engineering section from four to five engineers. The additional engineer will be assigned to Westchester.

One of the primary responsibilities of the field engineering position is to prioritize, direct and help manage the costs of our gas main replacement efforts. This is accomplished, in part, by working with the operating areas to optimize replace versus repair decisions and identify opportunities to insert existing leak prone pipe with new pipe and abandon redundant leak prone mains. Also, by having one point of contact in each operating organization, decisions for replacement or repair are streamlined through the organization.

Supporting an enhanced approach to project and program management, Gas Operations continues to utilize standard capital project documentation templates developed by the Company’s Cost Management Group, in the preparation of the annual capital budget.

Steam Operations, continues to utilize an enhanced approach to project management. The formalized use of project management in Steam Operations yields increasing benefits as more projects fall under the procedure criteria and lessons learned are identified and shared.

To enhance the skills of its project and program management personnel, Steam Distribution developed a training matrix identifying positions that require training and the level of training based on position, type of project, responsibility and role in the planning, implementation and oversight of projects. This matrix is reviewed and has been updated as training needs are identified.
Developing 20-Year Steam System Long Range Plan
The Company completed the development of a Steam System Long Range Plan in December 2011. PSC Staff had asked the Company to examine additional customer and resource scenarios on the Steam System. These detailed studies confirmed that the Company’s Steam Long Range plan is viable. The studies have been reviewed in detail with the PSC Staff.

As discussed in a previous section, we have updated and integrated our electric, steam, and gas long range plans into a single Integrated Long Range Plan (ILRP).

Developed 20-Year Gas System Long Range Plan
As discussed in a previous section, we have completed work on an integrated long-range plan. Gas Transmission Engineering and Gas Distribution Engineering worked with Strategic Planning and the Demand Forecasting group to identify and evaluate the potential changes in the business environment so that the Gas System Long Range Plan (GLRP) can be updated for the integrated plan.

Team 12: Energy Supply

Allowed for More Regular Examination of Electricity Supply
In 2010, additional hours were incorporated into the Audit Plan to conduct regular audits of functions related to electricity procurement. Auditing has maintained the additional hours dedicated to regular audits of electricity procurement functions that were incorporated into the annual Audit Plan as a result of the Management Audit. These hours are dedicated to review compliance with corporate policies and procedures associated with procurement decisions and the documentation required for entering into electricity supply contracts. Controls have been determined to be adequate and effective.

Explored External Asset Management Arrangements
The Company continues to include Asset Management Arrangements (AMA) in its Summer Natural Gas Purchase Plan, and look for ways to increase AMA activity.

In June 2012, Gas Supply entered into an asset management arrangement, where the counterparty pays the Company a fee to utilize the storage capacity that is open, as the Company injects gas into the storage during the summer. The counterparty submitted an unsolicited proposal requesting to utilize our open storage capacity during the summer. Once
the proposal satisfied our legal, regulatory, credit and operational requirements, a RFP was distributed to our counterparties soliciting bids for the open capacity. In addition, the Gas Planning Section performed an independent valuation of the proposal to ensure that the offers are in line with current market prices.

In addition, the Gas Supply Department introduced an Asset Management Arrangement key performance indicator, which measures the percentage of storage capacity that has been released to counterparties to manage. The objective is to increase or at least maintain current AMA activity, without sacrificing reliability.

During summer 2012, the Company executed a total of five AMAs, and as a result, gas supply costs in customer bills will be reduced by an estimated $9.7 million. The revenue received from the AMAs will reduce gas costs for customers as those benefits flow through the gas adjustment clause.

*Increased Interdepartmental Coordination in Energy Management*
Since the merger between gas and electricity hedging in 2011, controls and processes have been consolidated. Hedging protocols are now the same between the two former sections, which enhances risk controls. Reports have been created to give a holistic view of the regulated hedging program. Additionally, analysts have been cross-trained between the two former sections allowing greater flexibility in managing the hedging program, which became evident during the summer contingency. Additional cross-training in hedging of analysts from the Gas Planning group will also enhance the hedge strategy development.

Electric Supply and Gas Supply scheduling sections continue to meet on a regular basis to share pricing information, outage schedules, and hourly dispatch of units. Increased communication between the supply groups raises the awareness and transparency of steam and electric systems. This in turn helps to mitigate potential issues and lower the cost to our customers by effectively managing our resources. In addition, cross communication leads to knowledge transfer between the groups and professionally develops personnel on both sides.

*Documented Processes, Procedures, and Guidelines for Electric Supply and Scheduling*
The Electricity Supply and Scheduling group created a Physical Electricity Scheduling Manual and 12 process guides for the purchasing and scheduling of electricity to document the processes, procedures and guidelines followed in the department’s daily operations. The manual and process guides continue to be utilized by Electricity Supply’s personnel for
purchasing and scheduling functions. The documents are reviewed annually and updated to reflect process changes. The process guides play a very important role when training new personnel.

**Improved Procurement Methods**

Gas Supply continues to invite counterparties to submit alternate supply proposals/supply alternatives during the request for proposals (RFP) process, and evaluate unsolicited proposals. As a result, Gas Supply has learned about alternative purchasing points and asset management arrangements (AMA) structures, and continues to include them in their RFP’s. New supply points expand the range of suppliers that can participate in the Company’s natural gas procurement activities. Alternate purchase points include Marcellus Shale gas on Millennium, Tennessee Gas, and Tetco Pipelines. Any reductions in cost associated with these new supply arrangements will be passed on to customers through the gas adjustment clause.

Prior to each RFP, Gas Supply continues to request current credit information from the Energy Risk Management–Utilities department (ERM), and ERM continues to update its energy risk management systems with all active counterparty credit ratings, and any changes to credit ratings.

Since the Company has begun entering into Asset Management Arrangements, ERM evaluates the counterparty’s credit to determine the form and amount of financial assurance required in the event of non-performance. Depending on the creditworthiness of the counterparty, an unsecured credit limit may be extended or supplemented by credit enhancements such as a parental guarantee, cash or a letter of credit.
IX. Cost, Benefit and Risk Analysis

The Management Audit and its recommendations served as an important trigger for improving our approach to cost management; we continue to build upon that momentum and foster a cost conscious mindset in our corporate culture.

Now three years from the start of implementation and with work on 91 of 92 of the audit recommendations complete, many of the improvements we instituted are integrated into our operations. We used a systematic cost benefit analysis to assess, where quantifiable, the benefits of our recommendation implementation actions and promote a mindset among our employees that our implementation actions should be evaluated with a focus on our customers.

We have reviewed the costs and benefits for each recommendation and have either updated our original projections to reflect current information or confirmed that the cost and benefits have remained consistent with our original expectations. Due to the varied scope of individual recommendations, benefits fall into different categories: some are stated as one time savings, some as annual, and others described over a defined timeline. Some benefits are manifested as direct savings, while others as cost deferrals or avoidances. Since we were not able to identify quantifiable benefits for all recommendations, we made qualitative assessments to justify the implementation. We also considered risk reduction, increased transparency, process improvement, and impacts on reliability.

The following section provides a summary of the benefits from our major initiatives identified in the audit recommendations described under major categories. In addition, a summary of cost benefit analyses for all recommendations can be found in Appendix D.

Major Categories of Implementation Benefits

We have categorized implementation benefits into long range plan savings, annual savings, and qualitative benefits. Major efforts and benefits are summarized below:

Long Range Planning Savings
One of the most significant efforts of our audit implementation was the development of our long range plans and enhanced planning process. Our long range plans were developed for a
20-year planning horizon and, as such, the benefits are expected to accrue over that time frame. Our initial Electric, Gas and Steam long range plans identified over $4 billion in estimated cost savings, deferrals, and avoidances over the 20-year planning horizon.

In our 2010 plans, we identified several opportunities for reducing increases in our delivery costs. With the completion of an Integrated Long Range Plan this year, we have continued to build on those opportunities, such as asset utilization and work management practices, as well as pursuing new initiatives aimed at reducing our delivery costs in all three commodities. The Integrated Long Range Plan identifies over $2 billion in cost savings, deferrals, and avoidances across all three commodities over the 20-year planning horizon in addition to the $4 billion we identified in our 2010 plans.

For the Electric business we identified an additional savings of $4.2 billion in the Integrated Long Range Plan. The majority of the savings come from increasing asset utilization, which has deferred or avoided several large capital investments. This approach accounts for savings of $3.6 billion over 20 years. Improved asset-management practices, realized through enhanced monitoring and control, will allow us to defer additional capital investment of $600 million. The total savings of $4.2 billion is partially offset by $1.8 billion of capital needed to meet additional demand, yielding approximately $2.4 billion in net additional savings for this year’s ILRP initiatives. In addition to these savings, we have also identified potential opportunities like demand response and distributed generation that will reduce peak demand to further reduce infrastructure needs.

For our Gas business, our 20-year gas capital expenditure forecast has increased by approximately $600 million since the 2010 Plan. This increase is largely due to our recent expectation of additional oil conversions and public improvement investments. Through our integrated long range planning efforts, we have identified an additional $50 million in savings over the 20-year horizon to help offset cost increases. New initiatives contributing to the cost savings include smaller designs for regulators, use of competitive bid packages for main replacement work including the use of trenchless technology, and the potential reevaluation of some meter replacement mandates.

Our updated Steam Long Range Plan includes estimated operating expense savings of approximately $1.8 billion over the 20-year planning horizon. This is an increase of approximately $800 million from our 2010 plan. O&M savings are the result of the shutdown of the Hudson Avenue Boilers, management of the Ravenswood A-House and fuel savings from the Hudson Avenue boiler retirement, revised Steam Production Plant Operating Criteria, the
minimum oil burn settlement at the Federal Energy Regulatory Commission and natural gas addition projects at the 59th Street and 74th Street Generating Stations.

Many of the productivity improvements made through the implementation of individual recommendations are subsumed in our long range plans, and their associated benefits are accounted for in our estimated savings over the 20-year planning horizon. Our forecasted investments in our current rate plans and budgets are consistent with our Long Range Plans. As new savings are identified, they will be incorporated into future updates of our long range plans.

Asset Optimization
We have achieved cost avoidances of approximately $82 million in electric transmission and distribution capital spending through enhanced asset management strategies related to Audit recommendations. Our asset optimization strategies target investment where it is needed most, and reduce or eliminate investments as they reach points of diminishing returns. Implementation of new modeling methodologies, communications technologies and data sources has increased our visibility into the real-time and expected status of our equipment, and we are using this increased analytical capability to target investment. These efforts include:

- Development of cost-benefit profiles for electric distribution programs to assist system planners identify points of diminishing returns
- Utilization of new electric distribution modeling software products to help designers target investment to points where it is needed most
- Evaluation of programs for critical electric transmission assets (transformer and breakers programs) through enhanced engineering analysis of planned investments, and the curtailment and elimination of investments where they are shown to have insufficient benefit

These reduced funding levels are reflected in our current budgets and have been maintained in our forward looking forecasts and budgets. Our long range plans account for the benefits expected to accrue from the enhanced asset optimization strategies discussed above.

Work Management
Implementing a new Electric Operations work management system will help us achieve a percentage of the savings and cost avoidances described in the Electric Long Range Plan.
Total annual savings of $45 million net of ongoing information technology maintenance expenses will be realized upon full implementation in 2014. These savings are split between Capital and O&M.

These reduced funding levels are reflected in our forward looking forecasts and budgets.

Annual Savings
Implementation has created additional productivity and efficiency improvements to the benefit of our customers. We have identified approximately $11 million in annual savings and cost avoidances beyond those captured in our long range plans. These improvements have manifested themselves as savings and cost avoidances in the areas of improved project and program management, resource management and asset optimization.

Project Management
To improve project management at the business unit level, we established a more formal approach to project and program management within Electric Operations, Substation Operations, Gas Operations and Steam Operations. Ongoing costs to maintain the project management structure across these organizations is approximately $3 million; projected savings are expected to total $13 million across these organizations, for an expected net annual savings of $10 million. These savings continue to be achieved through productivity improvements on capital project and program expenditures. Actual savings going forward will depend on the number of projects and programs governed by this new approach.

Resource Management
We have achieved additional savings of approximately $850,000 annually through further improvements in resource planning.

- Use of Virtual Enterprise Modeling (VEMO) as a resource planning tool
- Increased efficiency and productivity of in-house design personnel and reduction of the outside services design budget
- Consolidation of our tree trimming contractor management functions
- Energy Management merging its gas and electricity hedging groups
These reduced funding levels have been maintained in our current and forward looking budgets.

Asset Optimization
In 2012, through our efforts to optimize our Company vehicle fleet, we have identified over 180 vehicles which were either removed from service or redeployed in lieu of purchases. Reductions are expected to save approximately $180,000 a year in avoided maintenance costs. Actual savings going forward will depend on the number of vehicles identified each year as a candidate for removal or redeployment.

The Company entered into Asset Management Arrangements (AMAs) to optimize its contractual gas storage assets. Through the execution of gas supply AMAs. We achieved an estimated savings of $2.3 million in 2010, $9.1 million in 2011 and $9.7 million in 2012. These cost reductions are passed on to customers through the gas adjustment clause.

Qualitative Benefits
For recommendations where we were not able to produce quantifiable benefits, we sought to identify qualitative measures that would provide adequate benefits to justify the implementation action. For example, we have adopted a “holistic” approach to cost management, enhanced Board oversight, increased focus on risk mitigation, and improved employee and public safety, as follows:

- We have included cost management as one of our three cultural imperatives. To support this cultural change, the Company adopted a “holistic” approach to cost management. Implementation of this holistic approach is driven by several key Audit Report recommendations. Benefits continue to manifest themselves as part of everyday operations and cultural change efforts.

- The revised Board and committee structure, the revised calendar, and committee dashboards on key operating and performance metrics, will enhance the Board’s oversight of management’s infrastructure planning and performance management. The Board Delegation of Authorities amendment will provide enhanced Board and Finance Committee oversight over large high-priority capital projects.

- With the implementation of Departmental Risk Profiles and new risk management system (CURA), there is a more focused monitoring of risk mitigation activities for key
corporate and departmental risks of the Company. While exact dollar savings cannot be quantified, the Company’s budget and planning processes are more closely aligned with risk assessments. Over time, classification of risks by mitigation status and continuous monitoring of Key Risk Indicators will improve strategic allocation of resources based on available risk information.

- The 50 mile gas main replacement target could reduce steel leaks by half, and cast iron leaks by two-thirds, over 25 years. The primary benefit of main replacement is the reduction in the risk of serious incidents caused by leaks. Public and employee safety is paramount to the way we manage and operate our gas system.

**Measuring and Sustaining Benefits of Implementation**

We have implemented changes to the way we track, measure and analyze our performance as it relates to Key Performance Indicators (KPI). KPIs facilitate the achievement of productivity improvements. Many of the cost savings initiatives described in the sections above are tracked through the use of KPIs.

We use a Corporate Performance Indicator (CPI) dashboard system to show the status of our KPIs. Enhanced functionality of this system has allowed each organization to proactively monitor its cost and performance trends. The new trending feature provides users with the flexibility to trend one or more KPIs at a time and view multiple trend charts. Employees can use the system to obtain current and trended performance of key indicators in a timely manner and assess if any action is required based on the trends provided.

Additionally, the implementation of Project One this year, supported by one integrated systems solution, will facilitate improved cost management practices. The new system will support a process that will enable employees to do business cost analysis and forecasting effectively, efficiently, and productively with more detail and longer length of financial forecasts and budgets. Better analytics and reporting will also enable the Company to assess the health of its infrastructure and capital equipment to support better long range planning.

Lastly our management variable pay plan defines the process by which management has the opportunity to receive part or all of its pay that is held at risk, pending successful achievement of KPIs. The weights assigned to the three components used to determine the MVP Award Fund (adjusted CECONY net income, operating budget, and Key Performance Indicators) place a greater emphasis on cost management. To link cost management performance to project and
program management, O&M and Capital budget indicators are used to measure performance on certain high priority projects and programs by cost and schedule targets. Operating performance targets are aligned with payouts to motivate employees to achieve the desired goals.

Conclusion: Creating Sustained Benefits for our Customers

We continue to challenge ourselves, seeking more cost-effective ways to do business and reduce cost to our customers. In the 2012 ILRP, we have identified over $6 billion in cost savings, deferrals, and avoidances across the three commodities over the 20-year planning horizon, which is $2 billion greater than the savings and cost avoidance identified in 2010 long range plans. These reductions are in part the result of further expanding and promoting specific Audit initiatives around new asset management strategies and improved work management practices. We continue to target investments with the lowest cost solution while maintaining reliability and reducing risk. Work management practices continue to evolve and improve, most notably through implementation of our new work management system in Electric Operations.

Beyond our long range plans, we have created additional benefits for our customers in our day to day operations. We initially identified approximately $11 million in annual savings and cost avoidances beyond those captured in our long range plans and those savings have been maintained going forward.
X. Discussions with PSC Staff

We continue to meet formally and informally with PSC Staff to discuss our actions to address the findings and recommendations of the audit, and to incorporate any feedback received into future plans. PSC Staff, including an internal team of its subject matter experts, has been active in reviewing documentation to confirm that completed actions satisfy the spirit and requirements of each recommendation. We have had numerous discussions, video conferences, and face-to-face meetings to continue a two-way dialogue and facilitate an effective recommendation close-out process.

This two-way communication process has been very beneficial. In addition to updates and discussions on the implementation process and progress, we have also had the opportunity to discuss the broader and more impactful topics of the Management Audit, such as the Company’s long range planning efforts and the barriers identified by Liberty. This feedback cycle has reinforced the value of this collaborative approach.

We remain committed to continue our work with the PSC and its Staff and other stakeholders to identify and implement improvements and changes together. We appreciate both the innovative approach that the PSC Staff took to this audit and its implementation, and their active participation and feedback throughout the process.

In all, this process has been successful in building an improved relationship which, in itself, addresses a barrier identified in the Audit Report. It is important that these discussions continue, as we believe that the result will be better regulatory approaches and benefits for customers.

We will continue to view the Management Audit as a way to improve and make us a better company. Working closely with the PSC and Staff has been an integral part of moving the Company in the right direction.
XI. Recommendation Completion and Status

Executing the Key Goals of the Implementation Process
The implementation of the recommendations is a company-wide effort that includes active participation of the Board and senior leadership. Con Edison considers the implementation effort an opportunity to improve its business processes and work more efficiently and effectively in our operations for the benefit of our customers.

Implementation actions are fully integrated into our broader effort to develop and execute a strategy for the long term sustainability of Con Edison. This strategy is established in the Company’s long range system visions and plans that serve as frameworks for capital investment and technological change. This strategy utilizes an enhanced holistic approach to cost management practices to realize our customers’ needs for safe, reliable, and cost-effective service.

We have reported implementation plan details as part of our commitment to continued action. We filed our Audit Implementation Plan in October 2009 and have filed updates every four months since. This Audit Implementation Plan Annual Report and Update includes four appendices.

Appendix A: Key of Recommendations
The table in Appendix A includes Con Edison’s audit recommendation numbering sequence, the Liberty Audit Report numbering sequence, the recommendation, and the executive sponsor.

Appendix B: Matrix of Recommendations
Appendix B is organized by team and provides the Con Edison team lead, milestones with associated dates and deliverables, and a discussion of each recommendation’s cost-benefit and risk analysis. This appendix is updated every four months to provide current status and additional detail.

Each of the 92 recommendations was subject to initial and ongoing review that continued through its completion. This review included analysis of implementation scope and its impact.
on customer bills, environmental sustainability, its contribution to overcoming the barriers and
to Con Edison’s continued success, linkage to the Company’s long range planning efforts, its
effect on internal controls, resulting business process changes, identification of metrics and
measurements for implementation success, and an analysis of cost, benefit and risk. We were
conscious of the relative priority of recommendations. Priority items, designated by an “H”
signifying a “high” priority in Appendix B, identify recommendations that yield either
significant strategic benefit or the most immediate benefit to customers.

Assessment and Status
Prior to the October 2009 filing of the AIP, the 12 teams examined the Audit Report’s
statements of relevant finding(s) and conclusion(s) and the associated recommendation(s).
Appendix B reflects the teams’ conclusions and approach regarding identified finding(s),
conclusion(s), and recommendations.

Recommendations were assessed under one of the four categories:

Accepted: Concurrence with Audit Report’s statement of relevant finding(s) and
conclusion(s); recommendation was appropriate based on preliminary cost
benefit and risk assessment; implementation was subject to additional cost
benefit and risk review.

Modified: Concurrence with Audit Report’s statement of relevant finding(s) and
conclusion(s); however an alternative approach was planned; implementation
was subject to additional cost benefit and risk review.

Under Review: Concurrence with Audit Report’s statement of relevant finding(s) and
conclusion(s); recommendation appeared appropriate; tentative
implementation plan was established subject to cost benefit and risk review.

Not Accepted: Audit report’s identification of relevant finding(s) and conclusion(s) was
reviewed; implementation activity was not warranted.

For each recommendation, Appendix B also provides estimated start and completion dates, a
brief statement of deliverables, a summary of cost-benefit, and risk analysis, an Assessment
category (as described above), and a Status indicator. Status was categorized by the following
categories:
In Progress: Actions are currently being taken

Completed: The Company’s response to this recommendation and its findings are complete; no further action is required or expected

Pending: Response to this recommendation was dependent upon sequencing of other initiatives that had to be completed first

Reevaluating: Actions were halted until further review was completed to justify continued action or suggest a change in course

Appendix C: Summary of Implementation Actions, by Team
Appendix C provides a summary of actions taken to address each of the 91 completed recommendations. Appendix C also provides detail for the one recommendation that remains in progress, Recommendation 71, to show the team lead(s), tentative major activities and milestones with associated dates, and progress every four months since the start of implementation.

The basis of our actions for each recommendation started with the initial establishment of expectations for what work would be completed. Each recommendation team was asked to complete a template that addressed the overall scope and objective of our response, as well as a schedule of major milestones for high level activities required to satisfy the recommendation. Details included the estimated start and end dates, and the actual end date when the activity or milestone is completed, a summary of the alternatives considered, and costs, benefits, and risks associated with implementation. Each time an AIP update was submitted, we updated this template to show progress.

Appendix D: Cost Benefit Summary for Recommendations
Costs and benefits for each recommendation are summarized in Appendix D.
Completion Summary Process and Status

Upon completion of all milestones for a particular recommendation, we draft a completion summary document to summarize actions taken and to discuss how implementation of the recommendation contributed to the achievement of strategic corporate objectives, what costs and benefits resulted, and how actions have been formally adopted into practice.

Through our third year of implementation, we have completed 91 of the 92 recommendations, 99% of the audit’s recommendations. We continue to make progress toward the completion of the one remaining recommendation. We have received and responded to a number of questions from the PSC Staff as follow-ups to our completion summaries.

We expect to be complete with implementation of all recommendations by March 2014.
XII. Conclusion

In this report, we have described many of the improvements made as a result of the management audit findings and recommendations and how we are integrating them in our operations. Our sustainability as a Company depends on our ability to maintain and expand upon the improvements discussed here. Our Board and senior leadership have played an integral part in this process by providing oversight and guidance.

We will maintain focus on our implementation efforts. We continue to look for ways to improve our business that will benefit our customers. We continue to work at all levels to strengthen our culture and become a better company. We are taking actions to support the Company’s long term goals, achieve benefits for our customers, and reinforce a cost conscious mindset with our employees. These actions support our mission to consistently provide our customers with safe, reliable and cost-effective service.
XIII. Appendices
### Appendix A: Key of Recommendations

<table>
<thead>
<tr>
<th>CE No.</th>
<th>Chapter/Section/ Recommendation #</th>
<th>Recommendation (w/referenced conclusions)</th>
<th>Team</th>
<th>Executive Sponsor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>III - Corporate Planning - 1</td>
<td>Improve the planning process. <em>(Conclusions 1, 2, 3, 4, 5)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>2</td>
<td>III - Corporate Planning - 2</td>
<td>Take the ERM process associated with operating risks to the next level. <em>(Conclusion 7)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>3</td>
<td>III - Corporate Planning - 3</td>
<td>Define the role of the Strategic Planning Unit. <em>(Conclusion 6)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>4</td>
<td>III - Corporate Planning - 4</td>
<td>Revisit the subjects investigated by the interdisciplinary teams. <em>(Conclusion 6)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>5</td>
<td>III - Corporate Planning - 5</td>
<td>Develop a comprehensive vision and 20-year master plan for the electric system. <em>(Conclusion 8)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>6</td>
<td>IV - Corporate Oversight - 1</td>
<td>Revise Board Committee Structure to better coordinate functions and to focus on infrastructure planning, oversight, and performance measurement. <em>(Conclusions 1 and 8)</em></td>
<td>2 - Board Leadership</td>
<td>E. Moore</td>
</tr>
<tr>
<td>7</td>
<td>IV - Corporate Oversight - 2</td>
<td>Continue efforts to identify board candidates with energy utility experience. <em>(Conclusion 2)</em></td>
<td>2 - Board Leadership</td>
<td>E. Moore</td>
</tr>
<tr>
<td>8</td>
<td>IV - Corporate Oversight - 3</td>
<td>Incorporate changes in management’s form and schedule for infrastructure planning and budgeting into a more structured, resequenced, and more intensive regimen of board review. <em>(Conclusions 5 and 6)</em></td>
<td>2 - Board Leadership</td>
<td>E. Moore</td>
</tr>
<tr>
<td>9</td>
<td>IV - Corporate Oversight - 4</td>
<td>Increase emphasis on efficiency and effectiveness in operations auditing. <em>(Conclusion 10)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy / C. Trahan</td>
</tr>
<tr>
<td>10</td>
<td>IV - Corporate Oversight - 5</td>
<td>Make consideration of Enterprise Risk Management a more structured part of audit planning. <em>(Conclusion 11)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy / C. Trahan</td>
</tr>
<tr>
<td>11</td>
<td>V - Incentive Compensation - 1</td>
<td>Increase the amount of stretch and put more pay at risk as part of a broad revamping of incentive compensation. <em>(Conclusions 7, 9, and 10)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>12</td>
<td>V - Incentive Compensation - 2</td>
<td>Before the study is done and implemented, reduce the emphasis on O&amp;M expense and increase the weighting for capital expenditure performance and the operating performance measures. <em>(Conclusions 7 and 8)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>13</td>
<td>VI - Performance Measures - 1</td>
<td>Develop a corporate-wide management information system. <em>(Conclusions 2, 4, 5, 6, 7)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>14</td>
<td>VII - Load Forecasting - 1</td>
<td>Analyze, and redirect as appropriate, the level of effort and sophistication applied to various load forecasting tasks and products, to better balance costs with product and user needs. <em>(Conclusion 2)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>CE No.</td>
<td>Chapter/Section/Recommendation #</td>
<td>Recommendation (w/referenced conclusions)</td>
<td>Team</td>
<td>Executive Sponsor</td>
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<tr>
<td>15</td>
<td>VII - Load Forecasting - 2</td>
<td>Find a better way to forecast growth in the peak gas load. <em>(Conclusion 8)</em></td>
<td>8 - Gas Capacity Planning</td>
<td>L. Tai / C. Trahan</td>
</tr>
<tr>
<td>16</td>
<td>VII - Load Forecasting - 3</td>
<td>Conduct an R&amp;VF review of certain aspects of its approach to forecasting. <em>(Conclusions 9, 13, 14)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>17</td>
<td>VII - Load Forecasting - 4</td>
<td>Evaluate the factors responsible for consistently under-estimating 5 and 10 year peak load forecasts; assure that any bias is removed from future forecasts. <em>(Conclusion 14)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>18</td>
<td>VII - Load Forecasting - 5</td>
<td>Expand load forecasting activities and capabilities to encompass analysis of uncertainties using sensitivity analyses, probabilistic tools or other applicable techniques. <em>(Conclusion 18)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>19</td>
<td>VII - Load Forecasting - 6</td>
<td>Develop an improved approach to the documentation, testing, and communication of forecast criteria and assumptions. <em>(Conclusion 19)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>20</td>
<td>VII - Load Forecasting - 7</td>
<td>Examine and implement as appropriate the efficiencies and quality improvements that might result from utilization of CECONY’s load research program, modified as cost-effective, to support load forecasting. <em>(Conclusion 26)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>21</td>
<td>VII - Load Forecasting - 8</td>
<td>Aggressively move forward with the major study planned by Market Research on efficiency potentials and include a special focus on efficiencies that can be targeted to specific networks. <em>(Conclusion 28)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>22</td>
<td>VII - Load Forecasting - 9</td>
<td>Evaluate options to enable the consideration of current and future load curtailment initiatives, both at CECONY and NYISO, for dependable network demand reduction. <em>(Conclusion 29)</em></td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>23</td>
<td>VII - Load Forecasting - 10</td>
<td>Establish a structured approach to the consideration of long-term eventualities that might significantly impact load forecasts, such as changes in trends, new technologies and new policies. <em>(Conclusion 30)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
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<tr>
<td>24</td>
<td>VIII - System Planning - Electric - 1</td>
<td>Evaluate reliability programs to determine if they should be terminated earlier to release capital expenditures for more cost effective reliability programs. <em>(Conclusion 3)</em></td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>25</td>
<td>VIII - System Planning - Electric - 2</td>
<td>Analyze networks and the 138 kV system designed to N-1 standards to determine the extent that maintenance activities can be performed at load levels less than peak load; where appropriate, incorporate maintenance design requirements into relevant design standards. <em>(Conclusion 6)</em></td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>26</td>
<td>VIII - System Planning - Electric - 3</td>
<td>Clarify transmission planning criteria with regard to transfers used during second contingency analysis. <em>(Conclusion 8)</em></td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>27</td>
<td>VIII - System Planning - Electric - 4</td>
<td>Perform a global review of all equipment ratings, input data, and time durations across the distribution and transmission areas to assure consistency and to justify and document</td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>CE No.</td>
<td>Chapter/Section/ Recommendation #</td>
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<td>Team</td>
<td>Executive Sponsor</td>
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<tr>
<td>28</td>
<td>VIII - System Planning - Electric - 5</td>
<td>Maintain the 2011 completion date for completion of network secondary topology updates and EPRI DEW software. (Conclusion 16)</td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>29</td>
<td>VIII - System Planning - Electric - 6</td>
<td>Perform a least cost system analysis that minimizes costs to customers with regard to implementation of 3G strategies. (Conclusion 17)</td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>30</td>
<td>VIII - System Planning - Electric - 7</td>
<td>Perform analyses to determine if peak demand can be reduced more economically than the addition of infrastructure. (Conclusion 19)</td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>31</td>
<td>VIII - System Planning - Electric - 8</td>
<td>Actively pursue the economic use of SCADA controlled network mid-point feeder sectionalizing switches or circuit breakers to reduce system investment. (Conclusion 20)</td>
<td>10 - Asset Optimization</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>32</td>
<td>VIII - System Planning - Electric - 9</td>
<td>Place all distribution tree trimming under a central corporate management function with accountability to corporate management. (Conclusion 22)</td>
<td>4 - Work Mgmt</td>
<td>J. Miksad / J. Ryan</td>
</tr>
<tr>
<td>33</td>
<td>VIII - System Planning - Electric - 10</td>
<td>Strengthen the distribution vegetation management inspection program with accountability. (Conclusion 23)</td>
<td>4 - Work Mgmt</td>
<td>J. Miksad / J. Ryan</td>
</tr>
<tr>
<td>34</td>
<td>VIII - System Planning - Electric - 11</td>
<td>Establish a base level of network reliability for new networks. (Conclusion 24)</td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>35</td>
<td>IX - System Planning Gas - 1</td>
<td>Maintain current information about CECONY's leak-prone pipe. (Conclusion 6)</td>
<td>7 - Gas Main Replacement</td>
<td>C. Trahan / D. Davidowitz</td>
</tr>
<tr>
<td>36</td>
<td>IX - System Planning - Gas - 2</td>
<td>Evaluate potential changes in the business environment for each of the businesses; for the GBU, Strategic Planning should advise Gas Engineering regarding potential demands on the gas transmission and distribution systems occasioned by those changes. (Conclusion 16)</td>
<td>11 - Gas and Steam Planning</td>
<td>C. Trahan / S. Shukla</td>
</tr>
<tr>
<td>37</td>
<td>IX - System Planning - Gas - 3</td>
<td>Report to stakeholders and the NYPSC on any expansion of the transmission and distribution systems required to serve winter-period electric power generation. (Conclusion 18)</td>
<td>11 - Gas and Steam Planning</td>
<td>C. Trahan / S. Shukla</td>
</tr>
<tr>
<td>38</td>
<td>X - System Planning - Steam - 1</td>
<td>Identify a Steam Master Plan and incorporate within it a greater emphasis on what is happening on and to its distribution system. (Conclusion 4)</td>
<td>11 - Gas and Steam Planning</td>
<td>C. Trahan / S. Shukla</td>
</tr>
<tr>
<td>39</td>
<td>XI - Budgeting - 1</td>
<td>Strongly link CECONY’s long-term electric plan with annual budgets, rate plans and 5-year capital plans. (Conclusion 4)</td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Miksad</td>
</tr>
<tr>
<td>40</td>
<td>XI - Budgeting - 2</td>
<td>Establish consistent, company-wide economic value analysis methods and metrics for capital projects and programs. (Conclusions 6 and 7)</td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy / C. Trahan</td>
</tr>
<tr>
<td>41</td>
<td>XI - Budgeting - 3</td>
<td>Work toward the re-establishment of multi-year electric rate cases. (Conclusion 3)</td>
<td>3 - Rate &amp; Financial Strategy</td>
<td>J. McMahon / R. Hoglund</td>
</tr>
<tr>
<td>42</td>
<td>XI - Budgeting - 4</td>
<td>Prioritize CECONY capital projects and allocate funding using long-term economic analysis metrics</td>
<td>1 - ELRP</td>
<td>L. Tai / J. McAvoy / J. Ryan</td>
</tr>
<tr>
<td>CE No.</td>
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<tr>
<td>43</td>
<td>XI - Budgeting - 5</td>
<td>as a significant decision factor. <em>(Conclusion 8)</em></td>
<td>2 - Board Leadership</td>
<td>J. Miksad</td>
</tr>
<tr>
<td>44</td>
<td>XI - Budgeting - 6</td>
<td>Require changes in capital projects and programs of more than 20 percent from the annual budget to be approved by the board of trustees. <em>(Conclusion 16)</em></td>
<td>4 - Work Mgmt</td>
<td>J. Miksad/J. Ryan</td>
</tr>
<tr>
<td>45</td>
<td>XII - Work Management - Cost Management - 1</td>
<td>Implement a holistic approach to cost management that is designed and built around three key elements: (a) a guiding philosophy; (b) a formal, structured cost management plan; and (c) building blocks of comprehensive supporting capabilities <em>(Conclusions 1)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy/C. Trahan</td>
</tr>
<tr>
<td>46</td>
<td>XII - Work Management - Cost Management - 2</td>
<td>As skilled people represent the cornerstone of the holistic approach, expand the role of cost management professionals to encompass tasks and accountabilities important to holistic cost management. <em>(Conclusion 5)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy/C. Trahan</td>
</tr>
<tr>
<td>47</td>
<td>XII - Work Management - Cost Management - 3</td>
<td>Establish a cost support organization that is (a) placed consistent with the priority of cost management; (b) serves the cost management needs of all levels of management; (c) develops a force of skilled cost professionals and assures those skills are continuously improved; and (d) has overall accountability for the development and implementation of the cost management program. <em>(Conclusion 5)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy/C. Trahan</td>
</tr>
<tr>
<td>48</td>
<td>XII - Work Management - Cost Management - 4</td>
<td>Provide training for managers, supervisors and cost support personnel in cost management techniques consistent with the holistic approach. <em>(Conclusions 1, 5, 6)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy/C. Trahan</td>
</tr>
<tr>
<td>50</td>
<td>XII - Work Management - Cost Management - 6</td>
<td>Sample Cost Management Implementation Tactics.</td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy/C. Trahan</td>
</tr>
<tr>
<td>51</td>
<td>XII - Work Management - Work Planning - 1</td>
<td>Establish fleet size criteria based on historical data on total vehicle usage hours versus total physical work performed in hours in the region for each vehicle class. <em>(Conclusion 6)</em></td>
<td>4 - Work Mgmt</td>
<td>J. Miksad/J. Ryan</td>
</tr>
<tr>
<td>52</td>
<td>XII - Work Management - Work Planning - 2</td>
<td>Perform in-depth reconciliation on cost estimates with substantial overrun to better understand the root causes of deviations. <em>(Conclusion 9)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy/C. Trahan</td>
</tr>
<tr>
<td>53</td>
<td>XII - Work Management - Resource Management - 1</td>
<td>Perform comprehensive resource analysis for all business units on a quarterly or semi-annual basis. <em>(Conclusions 3, 5, 9, 11)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>54</td>
<td>XII - Work Management - Resource Management - 2</td>
<td>Assess and monitor the productivity and cost impacts of carrying an extra trainee on some work crews on a continuous basis to achieve more efficient resource management. <em>(Conclusion 5)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>55</td>
<td>XII - Work Management -</td>
<td>Conduct a root cause analysis of the upward trend</td>
<td>9 -</td>
<td>L. Tai</td>
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<tr>
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<tr>
<td>56</td>
<td>XII - Work Management - Resource Management - 4</td>
<td>Review the roles of management, the Board and/or its committees after serious events such as the 2008 electrical fatalities. <em>(Conclusion 6)</em></td>
<td>2 - Board Leadership</td>
<td>E. Moore</td>
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<tr>
<td>57</td>
<td>XII - Work Management - Resource Management - 5</td>
<td>Increase efforts to segregate safety from contractual issues in management / bargaining unit dialog. <em>(Conclusion 6)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>58</td>
<td>XII - Work Management - Resource Management - 6</td>
<td>Review safety targets with the objective of adapting “stretch,” but attainable, levels that exceed historical averages. <em>(Conclusion 6)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>59</td>
<td>XII - Work Management - Resource Management - 7</td>
<td>Strengthen enforcement of contractor compliance with their safety programs. <em>(Conclusion 8)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>60</td>
<td>XII - Work Management - Resource Management - 8</td>
<td>Establish a corporate philosophy, policies and supporting guidelines for the balancing of in-house and contractor resources. <em>(Conclusion 12)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>61</td>
<td>XII - Work Management - Resource Management - 9</td>
<td>Establish a corporate philosophy, policies and supporting guidelines to provide managers and supervisors with a framework to manage overtime. <em>(Conclusion 9)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>62</td>
<td>XII - Work Management - Resource Management - 10</td>
<td>Prepare an analysis of corporate overtime expenditures that includes root causes of the upward trends and strategies for attaining more economic levels. <em>(Conclusion 9)</em></td>
<td>5 - Cost Mgmt J. McAvoy / C. Trahan</td>
<td></td>
</tr>
<tr>
<td>63</td>
<td>XII - Work Management - Performance Measurement - 1</td>
<td>Advance the continuous improvement efforts under The Way We Work program. <em>(Conclusions 1, 2)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>64</td>
<td>XII - Work Management - Performance Measurement - 2</td>
<td>Include pertinent productivity improvement goals in future KPIs at various management levels. <em>(Conclusion 3)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>65</td>
<td>XII - Work Management - Performance Measurement - 3</td>
<td>Implement a formal program for representatives from each region to share lessons learned in their respective fields. <em>(Conclusions 4, 9)</em></td>
<td>5 - Cost Mgmt J. McAvoy / C. Trahan</td>
<td></td>
</tr>
<tr>
<td>66</td>
<td>XII - Work Management - Performance Measurement - 4</td>
<td>Participate more actively in external information sharing efforts. <em>(Conclusion 10)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>67</td>
<td>XII - Work Management - Performance Measurement - 5</td>
<td>Perform analysis on work items with unacceptable QA rejection rates to isolate performance problems. <em>(Conclusion 5)</em></td>
<td>4 - Work Mgmt J. Miksad / J. Ryan</td>
<td></td>
</tr>
<tr>
<td>68</td>
<td>XIII - Project Management - Electric - Central Operations - 1</td>
<td>Improve resource planning for design personnel and other essential project personnel. <em>(Conclusion 3)</em></td>
<td>5 - Cost Mgmt J. McAvoy / C. Trahan</td>
<td></td>
</tr>
<tr>
<td>69</td>
<td>XIII - Project Management - Electric - Central Operations - 2</td>
<td>Bring a corporate total holistic approach to cost management to the project and program management efforts. <em>(Conclusion 6)</em></td>
<td>5 - Cost Mgmt J. McAvoy / C. Trahan</td>
<td></td>
</tr>
<tr>
<td>70</td>
<td>XIII - Project Management - Electric - Central Operations - 3</td>
<td>Strengthen Substation Operations program management processes by adding project management principles in a structured way.</td>
<td>5 - Cost Mgmt J. McAvoy / C. Trahan</td>
<td></td>
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</table>

84
<table>
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<th>CE No.</th>
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<th>Recommendation (w/referenced conclusions)</th>
<th>Team</th>
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<tbody>
<tr>
<td>71</td>
<td>XIII - Project Management - Electric - Electric Operations - 1</td>
<td>Implement a work management system in Electric Operations. <em>(Conclusion 1, 4, 5, 16)</em></td>
<td>4 - Work Mgmt</td>
<td>J. Miksad / J. Ryan</td>
</tr>
<tr>
<td>72</td>
<td>XIII - Project Management - Electric - Electric Operations - 2</td>
<td>Design and implement written project and program management procedures and expectations, including definitions of roles, responsibilities and expectations, cost control plans, and scope control procedures. <em>(Conclusion 2, 7, 9, 13, 14, 15, 18)</em></td>
<td>4 - Work Mgmt</td>
<td>J. Miksd / J. Ryan</td>
</tr>
<tr>
<td>73</td>
<td>XIII - Project Management - Electric - Electric Operations - 3</td>
<td>Implement a corporate total holistic approach to cost management. <em>(Conclusion 6)</em></td>
<td>5 - Cost Mgmt</td>
<td>J. McAvoy / C. Trahan</td>
</tr>
<tr>
<td>74</td>
<td>XIV - Project Management - Gas - 1</td>
<td>Staff a project coordination/specialist group under the Chief Distribution Engineer to assist in the execution of distribution capital projects such as the main replacement program. <em>(Conclusion 1)</em></td>
<td>11 - Gas and Steam Planning</td>
<td>C. Trahan / S. Shukla</td>
</tr>
<tr>
<td>75</td>
<td>XIV - Project Management - Gas - 2</td>
<td>Improve and expand the current project scope documentation to add sections on risks and rewards and alternative methods. <em>(Conclusion 2)</em></td>
<td>11 - Gas and Steam Planning</td>
<td>C. Trahan / S. Shukla</td>
</tr>
<tr>
<td>76</td>
<td>XIV - Project Management - Gas - 3</td>
<td>Start benchmarking with other urban utilities and utilize what these other utilities are doing better to improve the CECONY program and project management of capital projects. <em>(Conclusion 3)</em></td>
<td>11 - Gas and Steam Planning</td>
<td>C. Trahan / S. Shukla</td>
</tr>
<tr>
<td>77</td>
<td>XV - Project Management - Steam - 1</td>
<td>Identify projects requiring the application of project management techniques through a more formal, structured process. <em>(Conclusion 1)</em></td>
<td>11 - Gas and Steam Planning</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>78</td>
<td>XV - Project Management - Steam - 2</td>
<td>Train steam distribution operations personnel in work and project management techniques. <em>(Conclusion 3)</em></td>
<td>11 - Gas and Steam Planning</td>
<td>J. McAvoy</td>
</tr>
<tr>
<td>79</td>
<td>XVI - Supply Procurement - Electric - 1</td>
<td>Consolidate duplicative Energy Management operations in the electric and gas hedging functions. <em>(Conclusion 2)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>80</td>
<td>XVI - Supply Procurement - Electric - 2</td>
<td>Develop a comprehensive portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans. <em>(Conclusions 3, 7, 14)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>81</td>
<td>XVI - Supply Procurement - Electric - 3</td>
<td>Revise the performance measures (KPIs) for energy management to provide metrics and incentives that align with electric procurement objectives. <em>(Conclusion 4)</em></td>
<td>9 - Performance Measurement</td>
<td>L. Tai</td>
</tr>
<tr>
<td>82</td>
<td>XVI - Supply Procurement - Electric - 4</td>
<td>Identify, analyze and document all reasonable alternatives to its existing sources for both capacity and energy. Alternatives that are superior to the status quo electric resources should be implemented. <em>(Conclusions 8, 9, 11)</em></td>
<td>6 - Load Forecasting</td>
<td>L. Tai</td>
</tr>
<tr>
<td>83</td>
<td>XVI - Supply Procurement - Electric - 5</td>
<td>Internal Auditing should schedule more frequent audits of electric procurement decisions, documentation for entering into electric supply contracts, and daily purchase decisions. <em>(Conclusion 17)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
</tr>
<tr>
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<tr>
<td>84</td>
<td>XVI - Supply Procurement - Electric - 6</td>
<td>Document processes, procedures, and guidelines for electric supply and scheduling, and for the 20 percent purchase flexibility in electric hedging. <em>(Conclusion 20)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
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<tr>
<td>85</td>
<td>XVII - Supply Procurement - Gas - 1</td>
<td>Make finding means for increasing interdepartmental coordination an Energy Management priority. <em>(Conclusion 3)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
</tr>
<tr>
<td>86</td>
<td>XVII - Supply Procurement - Gas - 2</td>
<td>Provide for more regular examination of Gas Supply’s award of supply contracts by Internal Auditing. <em>(Conclusions 7, 8)</em></td>
<td>8 - Gas Capacity Planning</td>
<td>L. Tai / C. Trahan</td>
</tr>
<tr>
<td>87</td>
<td>XVII - Supply Procurement - Gas - 3</td>
<td>Explore applying probability-of-occurrence analysis to its supply-capacity planning. <em>(Conclusion 13)</em></td>
<td>8 - Gas Capacity Planning</td>
<td>L. Tai / C. Trahan</td>
</tr>
<tr>
<td>88</td>
<td>XVII - Supply Procurement - Gas - 4</td>
<td>Expand Gas Supply’s range of potential capacity alternatives as it considers firm customers’ peak-day requirements for supply. <em>(Conclusions 14, 15)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
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<tr>
<td>89</td>
<td>XVII - Supply Procurement - Gas - 5</td>
<td>Conduct occasional Gas Supply tests to identify potential additional types of supply arrangements. <em>(Conclusion 18)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
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<tr>
<td>90</td>
<td>XVII - Supply Procurement - Gas - 6</td>
<td>Keep financial and credit information for gas suppliers current. <em>(Conclusion 21)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
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<tr>
<td>91</td>
<td>XVII - Supply Procurement - Gas - 7</td>
<td>Find specific, objective ways for Gas Supply to evaluate its own performance. <em>(Conclusion 28)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
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<tr>
<td>92</td>
<td>XVII - Supply Procurement - Gas - 8</td>
<td>Solicit proposals for external asset management. <em>(Conclusions 29, 31)</em></td>
<td>12 - Energy Supply</td>
<td>L. Tai</td>
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</table>
## Appendix B: Matrix of Recommendations

<table>
<thead>
<tr>
<th>Team</th>
<th>CE No.</th>
<th>High Priority</th>
<th>Chapter Reference</th>
<th>Recommendation (w/referenced conclusions)</th>
<th>Start Date</th>
<th>Completion Date (Est.)</th>
<th>Completion Date (Act.)</th>
<th>Deliverable(s)</th>
<th>Summary of Cost, Benefit, and Risk Analysis</th>
<th>Assessment</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>H</td>
<td>III - Corporate Planning - 1</td>
<td>Improve the planning process. (Conclusions 1, 2, 3, 4, 5)</td>
<td>4/09</td>
<td>7/10</td>
<td>7/10</td>
<td>Updated Corporate Instructions on Standardized Business Plans and processes</td>
<td>Direct costs of implementation were negligible, as deliverables are mainly embodied in administrative changes to the Company’s annual business planning process. The main benefits are greater alignment of objectives and goals across business units, and stronger linkage of short-term to longer-term strategies. The business planning process provides detailed work plans that are designed to achieve the goals and strategic objectives and adherence with the Company’s cost management initiatives. Work plans must demonstrate that the appropriate work has been proposed for the forecast period, with particular attention paid to next budget year’s activity. Capital and operating projects and programs will be judged based on their alignment with the Company’s strategic priorities (the resource optimization process) so that funds are allocated efficiently to manage risks and meet strategic objectives.</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td>III - Corporate Planning - 2</td>
<td>Take the ERM process associated with operating risks to the next level. (Conclusion 7)</td>
<td>9/09</td>
<td>4/10</td>
<td>4/10</td>
<td>Summary of Process Improvements</td>
<td>The total cost to implement this recommendation was $214,200. With the implementation of Departmental Risk Profiles and new risk management system (CURA), there is a more focused monitoring of risk mitigation activities for key corporate and departmental risks of the Company. While exact dollar savings cannot be quantified, periodic risk assessments are better aligned with the Company’s budget and planning processes. Over time, classification of risks by mitigation status and continuous monitoring of Key Risk Indicators will improve strategic allocation of resources based on available risk information.</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>H</td>
<td>III - Corporate Planning - 3</td>
<td>Define the role of the Strategic Planning Unit. (Conclusion 6)</td>
<td>3/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Updated Corporate Policy Instruction that states the role of Strategic Planning</td>
<td>The costs associated with implementing this recommendation consisted of benchmarking, research, analysis, and meetings with internal company officers. This equates to approximately $75,000 based on labor costs and subscriptions to research databases. The benefits of refining the role of Strategic Planning include an improved alignment of capital investment and operational spend with defined corporate priorities. The savings are expected to exceed the $75,000 cost incurred.</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td>III - Corporate Planning - 4</td>
<td>Revisit the subjects investigated by the interdisciplinary teams. (Conclusion 6)</td>
<td>5/09</td>
<td>12/10</td>
<td>12/10</td>
<td>Document and refine the interdisciplinary team launch process</td>
<td>Costs to reevaluate the ongoing interdisciplinary teams and to improve the strategic planning process were not significant, and included use of Company resources and payment for supporting external services/products (e.g., research reports). Future actions of the interdisciplinary teams are expected to yield benefits to customers and the Company. Interdisciplinary teams will bring out the necessary expertise from various parts of the Company to provide strategic solutions to multidisciplinary issues.</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
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<tr>
<td>Team</td>
<td>CE No.</td>
<td>High Priority</td>
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<tr>
<td>5 H</td>
<td>III - Corporate Planning - 5</td>
<td>Develop a comprehensive vision and 20-year master plan for the electric system. (Conclusion 8, 9)</td>
<td>3/09</td>
<td>12/10</td>
<td>12/10</td>
<td>A 20-year integrated plan for the electric system (Electric Long Range Plan or ELRP) that: o Defines the long-term vision and strategic goals of the electric system and clearly links programs and projects to the attainment of those measurable goals. o Evaluates customer bill and rate impact (affordability) and reliability in light of required system investment and various legislative, regulatory, and technology issues, and the impact of potential alternatives. o Develops the framework for more integrated transmission, substation, and distribution planning which incorporates innovative solutions to meet customer expectations. o Provides the linkage of our near-term plans and requests (i.e., rate case and other filings) to the 20-year integrated plan, by demonstrating that the near-term plans are the first steps in the longer program.</td>
<td>Costs to develop the 2010 ELRP totaled $2.2 million, and through the efforts of the long range planning process, we identified $3.1 billion in estimated cost avoidances and savings over the 20-year horizon. Through the efforts of the Integrated Long Range Plan we have identified $2.4 billion in net electric savings and avoided capital investment over the 20 year planning horizon. This is an addition to the $3.1 billion identified in the 2010 plan. Total electric savings identified in the ILRP are $4.2 billion over 20 years, which are partially offset by $1.8 billion of capital needed to meet additional demand during this timeframe.</td>
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<td>21 H</td>
<td>VII - Load Forecasting - 8</td>
<td>Aggressively move forward with the major study planned by Market Research on efficiency potentials and include a special focus on efficiencies that can be targeted to specific networks. (Conclusion 28)</td>
<td>11/08</td>
<td>12/09</td>
<td>12/09</td>
<td>Energy efficiency market potential study with review and evaluation focusing on system and network needs</td>
<td>The cost of the energy efficiency study was $825,000 and was funded in Case 07-E-0523 for the 2008 – 2009 rate year. All efficiency programs are subject to a Total Resource Cost test and the study helps us design better programs and address barriers to demand side management. Demand side management (demand response and energy efficiency) may defer or eliminate the need for expensive capital infrastructure, while at the same time reducing green house gas (GHG) emissions and enhancing reliability.</td>
<td>Accepted</td>
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<td>22 H</td>
<td>VII - Load Forecasting - 9</td>
<td>Evaluate options to enable the consideration of current and future load curtailment initiatives, both at CECONY and NYISO, for dependable network demand reduction. (Conclusion 29)</td>
<td>6/09</td>
<td>11/11</td>
<td>3/11</td>
<td>Analysis of pilot results</td>
<td>Total costs for all Peak Load Shaving Programs during the 2010 program year were $985,000 or approximately 4% of the projected two year costs of $22 million. These costs are reflective of program start-up and low participation, but should increase as the program matures over the next few years. The peak load shaving programs are not mature, and had limited customer enrollment. As a result, there is not enough current information to evaluate whether the programs are either cost or operationally (from the utility perspective) effective. The pilots are currently expected to run through the end of 2012 and at that time we will have a better understanding of the potential for all peak shaving programs. However, we will continue to evaluate each pilot and program on an annual basis and adapt the programs as appropriate.</td>
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<td>34 H</td>
<td>VII - System Planning - Electric - 11</td>
<td>Establish a base level of network reliability for new networks. (Conclusion 24)</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Prepare white paper on ideal network reliability for new networks</td>
<td>Establishing a base level of network reliability allows Con Edison to identify the networks on which reliability funds should be targeted in order to provide an overall system improvement. Since the date of the close-out summary, the risk of network shutdown was reduced by 51% for the top 20 highest risk networks while effectively maintaining existing acceptable risk levels for the remaining networks. The company is on target to attain the base level of network reliability by the end of 2015. See Recommendation 24 for associated benefits.</td>
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<td>49</td>
<td>H</td>
<td>XI - Budgeting - 1</td>
<td>Strongly link CECONY’s long-term electric plan with annual budgets, rate plans and 5-year capital plans. (Conclusion 4)</td>
<td>3/09</td>
<td>12/10</td>
<td>12/10</td>
<td>The ELRP, as discussed in recommendation 5, will link annual budgets, rate plans, and the 5-year capital plan to the attainment of longer term system performance goals.</td>
<td>Costs and benefits achieved under implementation of this recommendation are considered in the development of the Company’s Electric Long Range Plan and improvements to its annual business planning process, as discussed in Recommendations 1 and 5.</td>
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<td>42</td>
<td>H</td>
<td>XI - Budgeting - 4</td>
<td>Prioritize CECONY capital projects and allocate funding using long-term economic analysis metrics as a significant decision factor. (Conclusion 8)</td>
<td>3/09</td>
<td>12/10</td>
<td>12/10</td>
<td>The ELRP, as discussed in recommendation 5, will show the expected benefits of our electric projects and programs, as detailed in annual budgets, rate plans, and 5-year capital plans, in terms of cost, performance and risk over the long-term horizon. Projects and programs will be prioritized by customer needs, corporate strategic objectives, and management of operating risks.</td>
<td>Costs and benefits achieved under implementation of this recommendation are considered in the development of the Company’s Electric Long Range Plan and improvements to its capital program and project prioritization practices, as discussed in Recommendations 5 and 40.</td>
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<td>IV - Corporate Oversight - 1</td>
<td>Revise Board Committee Structure to better coordinate functions and to focus on infrastructure planning, oversight, and performance measurement. (Conclusions 1 and 8)</td>
<td>8/09</td>
<td>11/10</td>
<td>11/10</td>
<td>Adopt revised Committee structure and 2010 calendar. Create a dashboard for each Committee and Board of key operating and performance metrics, risks and projects.</td>
<td>Implementation costs were minimal, as this is a recalibration of functions related to the duties and responsibilities of the respective Board committees. The benefit is expected to be enhanced Board engagement and oversight. The revised Board and committee structure, and the revised calendar will allow the committees, as appropriate, to enhance oversight of management’s infrastructure planning and performance management.</td>
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<td>IV - Corporate Oversight - 2</td>
<td>Continue efforts to identify board candidates with energy utility experience. (Conclusion 2)</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Review director search process with Executive Search Firm and Lead Director.</td>
<td>Such expertise enhances the Board focus on issues that directly impact the Company.</td>
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<td>IV - Corporate Oversight - 3</td>
<td>Incorporate changes in management’s form and schedule for infrastructure planning and budgeting into a more structured, resequenced, and more intensive regimen of board review. (Conclusions 5 and 6)</td>
<td>8/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Review management’s form and schedule for infrastructure planning and budgeting. Adopt revised Committee structure and 2010 calendar</td>
<td>Implementation allows for a more structured review of short and long-range system needs in advance of annual budgeting, and provides for planning and budget review by the committees and the Board.</td>
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<td>43</td>
<td>XI</td>
<td>Budgeting - 5</td>
<td>XI - Budgeting - 5</td>
<td>Require changes in capital projects and programs of more than 20 percent from the annual budget to be approved by the board of trustees. (Conclusion 16)</td>
<td>8/09</td>
<td>11/10</td>
<td>11/10</td>
<td>Review results of revised Committee structure and budget process with Corporate Governance &amp; Nominating Committee to determine whether to implement Conclusion 16 Draft delegation language to require approval by the Board or the Finance Committee, if required</td>
<td>Implementation costs to create Committee dashboards and amend the Delegation of Authorities were minimal. The benefit is expected to be enhanced Board and Finance Committee engagement and oversight. The Delegation amendment will provide enhanced Board and Finance Committee oversight over certain capital projects.</td>
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<td>56</td>
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<td>XII - Work Management - Resource Management - 4</td>
<td>Review the roles of management, the Board and/or its committees after serious events such as the 2008 electrical fatalities. (Conclusion 6)</td>
<td>8/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Discuss roles and process with Board members</td>
<td>Benefits include enhancing the Board’s role in the oversight of the Company’s management of risks, including the oversight of risks that could lead to serious events.</td>
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<td>3 Rate &amp; Financial Strategy</td>
<td>41  H</td>
<td>XI - Budgeting - 3</td>
<td>Work toward the re-establishment of multi-year electric rate cases. (Conclusion 3)</td>
<td>8/09</td>
<td>5/10</td>
<td>4/10</td>
<td>Efforts to seek multi-year rate arrangements</td>
<td>A multi-year rate plan reduces the risks associated with the rate-making process by reducing the frequency of the rate cycle, and provides for additional flexibility with respect to managing the business. Risks inherent in a multi-year arrangement can be mitigated by the terms of the arrangement, including triggers to re-open issues and deferral of unexpected costs. On average, incremental non-staffing costs associated with electric rate case filings are between $1.2 and $1.6 million. The main components of these costs are for consultants and expert witnesses, public notice ads, travel expenses, and printing. Some of these costs (at least 20%), plus some staff positions, may be avoided in the longer term, to the extent that multi-year rate plans become the norm and the number of interim proceeding and collaboratives are not significant.</td>
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<td>4 Work Management</td>
<td>32 H</td>
<td>VIII - System Planning - Electric - 9</td>
<td>Place all distribution tree trimming under a central corporate management function with accountability to corporate management. (Conclusion 22)</td>
<td>1/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Consolidate all distribution line clearance activities under one management organization.</td>
<td>We continue to see improvements in our tree trimming contractor costs since the consolidation of the program under one organization, the gross unit cost in 2009 was approximately $5.080/mile and in 2011 it was approximately $4.960/mile. Qualitative benefits in the form of quality of workmanship, safety improvements, specification compliance and reliability improvements.</td>
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<td>33 H</td>
<td>VIII - System Planning - Electric - 10</td>
<td>Strengthen the distribution vegetation management inspection program with accountability. (Conclusion 23)</td>
<td>6/09</td>
<td>7/09</td>
<td>6/09</td>
<td>Implement Electric Operations Quality Assurance program that includes random field reviews of completed tree trimming work to ensure full compliance to the specification.</td>
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<td>44 H</td>
<td>XI - Budgeting - 6</td>
<td>Establish formal informational feedback loops for project analysis and project prioritization. (Conclusion 17)</td>
<td>9/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Update CI-291. Formalize process to evaluate merits of specific projects and overall portfolios.</td>
<td>Feedback loops will provide opportunities to evaluate and adjust projects and programs to ensure the appropriate balance of cost and value. An annual review of the capital optimization portfolio will result in improved capital allocation decisions to achieve maximum value for set spend level. The cost-benefit is accounted for under Recommendations 24, 72 and 40.</td>
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<td>51</td>
<td>XII - Work Management - Work Planning - 1</td>
<td>Establish fleet size criteria based on historical data: on total vehicle usage hours versus total physical work performed in hours in the region for each vehicle class. (Conclusion 6)</td>
<td>4/09</td>
<td>4/09</td>
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<td>Establish vehicle metrics in order to establish baseline of vehicle utilization. Define vehicle utilization policy and protocol. Create transparent business information for operating groups. (Due to limited availability of usage hours data, alternative metrics will be used as basis for evaluation),</td>
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<td>67 H</td>
<td>XII - Work Management - Performance Measurement - 5</td>
<td>Perform analysis on work items with unacceptable QA rejection rates to isolate performance problems. (Conclusion 5)</td>
<td>7/09</td>
<td>7/09</td>
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<td>8/09</td>
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<td>8/09</td>
<td>Significant and marked improvements have been demonstrated in 2007, 2008, and 2009 YTD Electric Operations QA performance. The alleged adverse trends cited in the Liberty audit report are due to changes in measuring techniques and personnel.</td>
<td>QA performance has continued to steadily improve. In 2011 compliance with the inspection and construction metrics was 95%. We are on track to achieve the 2012 year end goal of 96% compliance with the inspection and construction metrics.</td>
<td>Accepted</td>
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<td>71 H</td>
<td>XIII - Project Management - Electric - Electric Operations - 1</td>
<td>Implement a work management system in Electric Operations. (Conclusion 1, 4, 5, 16)</td>
<td>5/09</td>
<td>5/09</td>
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<td>3/14</td>
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<td>Development of business case, implementation plan, and change management communication plan.</td>
<td>In 2011, actual project costs were $25.4 million versus a budget of $35.2 million; the current working estimate for year end 2012 is $30.8 million versus a budget of $39.8 million. Total annual savings of $45.1 million net of ongoing information technology maintenance expenses will be realized upon full implementation in 2014.</td>
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<td>72 H</td>
<td>XIII - Project Management - Electric - Electric Operations - 2</td>
<td>Design and implement written project and program management procedures and expectations, including definitions of roles, responsibilities and expectations, cost control plans, and scope control procedures. (Conclusion 2, 7, 9, 13, 14, 15, 18)</td>
<td>8/09</td>
<td>8/09</td>
<td>12/09</td>
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<td>Develop a project management specification for Electric Operations.</td>
<td>Three new project managers and nine staff members have been hired into the Electric Operations Project Management Organization. They are responsible for schedule, cost, and quality performance for various projects and programs across the Manhattan, Bronx/Westchester and Brooklyn/Queens regions. This group has expanded from our original staffing level estimate of eight to twelve individuals. As a result, annual operating costs are $1.9 million, Annual productivity improvements of 1% on the total Electric Operations capital spending level is expected, resulting in savings of $8.1 million annually. Net of annual operating costs, savings are $6.2 million annually.</td>
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<td>5</td>
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<td>IV - Corporate Oversight - 4</td>
<td>Increase emphasis on efficiency and effectiveness in operations auditing. (Conclusion 10)</td>
<td>6/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Establish a new section in Auditing focused on construction projects, construction contractors and energy services; Obtain analytical audit extraction software; Integrate in the 2010 Audit Plan operations audits dealing with efficiency and effectiveness.</td>
<td>Approximately $550,000 will be expended annually to maintain the new Auditing section. An additional $150,000 (one time cost) has been expended to purchase the ACL analytical tool. The measures are also expected to help to deter and prevent recurrence of fraudulent activities in these areas. In addition to identifying inappropriate overcharges, the new group will work with Construction and other Corporate organizations to identify process improvements and controls and standardize policies and procedures to further reduce potential inappropriate charges and payments to contractors.</td>
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<td>10</td>
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<td>IV - Corporate Oversight - 5</td>
<td>Make consideration of Enterprise Risk Management a more structured part of audit planning. (Conclusion 11)</td>
<td>8/09</td>
<td>11/09</td>
<td>10/09</td>
<td>The 2010 Audit Plan will contain a cross reference to the applicable risk the audit will cover in the Enterprise Risk Management program.</td>
<td>There were no incremental costs expended to improve alignment between the annual Audit Plan and ERM Program. However, certain benefits, including proactive risk assessment and evaluation and reduction of risk exposure, are expected to be realized.</td>
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<td>40</td>
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<td>XI - Budgeting - 2</td>
<td>Establish consistent, company-wide economic value analysis methods and metrics for capital projects and programs. (Conclusions 6 and 7)</td>
<td>7/09</td>
<td>6/10</td>
<td>6/10</td>
<td>Implement portfolio management system to enable comparable analyses to determine prioritization of capital projects.</td>
<td>Total cost is $1 million for implementation and $300,000 for annual maintenance. To date, benefits have been realized in the management of the Common Capital Portfolio; we have strategically reinvested approximately seventeen million dollars in critical infrastructure type projects which otherwise would have been deferred to outer years at a higher cost.</td>
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<td>45</td>
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<td>XII - Work Management - Cost Management - 1</td>
<td>Implement a holistic approach to cost management that is designed and built around three key elements: (a) a guiding philosophy; (b) a formal, structured cost management plan; and (c) building blocks of comprehensive supporting capabilities (Conclusions 4, 9)</td>
<td>2/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Formal Cost Management Program Document or Procedure</td>
<td>An enhanced “holistic” approach to cost management will yield many benefits. Costs associated with establishing the required groundwork totaled $715,000, and included: extensive team time over the span of one year to coordinate and implement the work plan ($500,000), a third party assessment ($150,000), and the cost to develop new reporting tools ($65,000). Benefits achieved will exceed these costs and result from increased alignment, continued business process improvement, increased communication and awareness, and consistency.</td>
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<td>46</td>
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<td>XII - Work Management - Cost Management - 2</td>
<td>As skilled people represent the cornerstone of the holistic approach, expand the role of cost management professionals to encompass tasks and accountabilities important to holistic cost management. (Conclusion 5)</td>
<td>6/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Evaluation of Roles and Responsibilities &amp; revised Position Guides for Cost Management Personnel</td>
<td>Total costs to achieve implementation objectives were approximately $5,000, reflecting nearly 100 hours of direct work. Benefits are expected to exceed the costs to implement this recommendation. The expansion of the roles and responsibilities of cost professionals, more stringent qualification requirements, and support for professional development of Con Edison cost professionals enables the adoption of an enhanced, holistic cost management program that will support initiatives to formalize the cost management program, balance focus on reporting and root cause analysis, support Line Management, and improve efficiency.</td>
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<td>XII - Work Management - Cost Management - 3</td>
<td>Establish a cost support organization that is (a) placed consistent with the priority of cost management; (b) serves the cost management needs of all levels of management; (c) develops a force of skilled cost professionals and assures those skills are continuously improved; and (d) has overall accountability for the development and implementation of the cost management program. (Conclusion 5)</td>
<td>2/09</td>
<td>10/09</td>
<td>10/09</td>
<td>Recommendation for new organizational structure for Cost Management activities</td>
<td>The creation of a centralized Cost Management Director position who reports directly to the President of CECONY has led to a higher priority of cost, increased feedback and oversight. This new alignment ensures consistency of communication across all organizations and independence of cost management personnel. This organizational structure and enhanced role of Cost Management will be integrated with the broader organizational assessment of Con Edison.</td>
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<td>XII - Work Management - Cost Management - 4</td>
<td>Provide training for managers, supervisors and cost support personnel in cost management techniques consistent with the holistic approach. (Conclusions 1, 5, 6)</td>
<td>6/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Training and Curriculum for Cost Management and Line Personnel</td>
<td>The costs in achieving these objectives totaled approximately $8,000; we expect to achieve savings greater than this cost. Providing training for cost professionals and line personnel advances the Company’s effort to adopt an enhanced approach to Cost Management. Specifically, building the skill sets of these key players will support the Company’s initiatives to formalize the cost management program, balance focus on reporting and root cause analysis, develop alternatives and action plans, support line management, improve efficiency, and communicate more effectively.</td>
<td>Accepted</td>
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<td>49</td>
<td></td>
<td>1</td>
<td>XII - Work Management - Cost Management - 5</td>
<td>General Recommendation Implementation Guidance.</td>
<td>6/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Formal Cost Management Program Document or Procedure</td>
<td>The cost for implementing this recommendation was approximately $50,000. Continued application of enhanced analytical methods for tracking project cost by element of expense will result in inherent savings and a potential reduction in project overruns. Expected savings will exceed cost of implementation, and will result from better real-time understanding of cost variances and the impact of scope changes and project schedules, and more accurate long-term planning for cash flows, schedules and budgets.</td>
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<td>50</td>
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<td>XII - Work Management - Cost Management - 6</td>
<td>Sample Cost Management Implementation Tactics.</td>
<td>2/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Formal Cost Management Program Document or Procedure</td>
<td>The recommended “Cost Management Implementation Tactics” have implemented as part of the Company’s implementation of a holistic approach to cost management. For implementation detail, please see Recommendation 45.</td>
<td>Accepted</td>
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<td>52 H</td>
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<td>2</td>
<td>XII - Work Management - Work Planning - 2</td>
<td>Perform in-depth reconciliation on cost estimates with substantial overrun to better understand the root causes of deviations. (Conclusion 9)</td>
<td>4/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Analysis of projects with cost overruns and variance reporting templates</td>
<td>The estimating department of Central Engineering established Key Performance Indicators (KPIs) to track the completion of monthly/quarterly cost comparisons analysis between estimates vs. CWES. The primary objective is to analyze all estimates greater than $2M and or estimates that exceed the predetermined +/- 10% accuracy margin requirement. A root cause determination is established for all variances which then facilitate the establishment of lessons learned criteria to be applied to future estimates. ghout Central Engineering and Construction.</td>
<td>Accepted</td>
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<td>62 H</td>
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<td>XII - Work Management - Resource Management - 10</td>
<td>Prepare an analysis of corporate overtime expenditures that includes root causes of the upward trends and strategies for attaining more economic levels. (Conclusion 9)</td>
<td>10/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Analysis of overtime expenditures and guidance document as per Recommendation 61</td>
<td>No incremental cost. The key benefits are expected to be improved overtime cost control and increased accountability. The Local Guidance Document will afford each organization greater structure in making overtime decisions while maintaining the flexibility to manage its overtime budget. As a result, we expect annual savings of approximately $1 million.</td>
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<td>3</td>
<td>XII - Work Management - Performance Measurement - 3</td>
<td>Implement a formal program for representatives from each region to share lessons learned in their respective fields. (Conclusions 4, 9)</td>
<td>10/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Implementation of Lessons Learned discussions at Work Plan and other meetings</td>
<td>We have transitioned to using a central Lessons Learned site which has been established for use by all project managers through out the Company. This Enterprise “Lessons Learned” repository serves as a one-stop shop for communicating and sharing information.</td>
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<td>68</td>
<td>XIII</td>
<td>Electric - Central Operations 1</td>
<td>Improve resource planning for design personnel and other essential project personnel. (Conclusion 3)</td>
<td>10/09</td>
<td>6/10</td>
<td>6/10</td>
<td>Staffing plan</td>
<td>Improved resource planning for design personnel and other essential project personnel in Central Engineering have resulted in cost savings of approximately $262,000 annually through increased efficiency and productivity of in-house personnel and reduction of outside the outside services design budget.</td>
<td>Accepted</td>
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<tr>
<td>69 H</td>
<td>XIII</td>
<td>Electric - Central Operations 2</td>
<td>Bring a corporate total holistic approach to cost management to the project and program management efforts. (Conclusion 6)</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>The Lessons Learned Template will be revised to include a cost management component to the process to be utilized in future projects.</td>
<td>The benefit of incorporating cost management practices into the lessons learned phase will be to provide better information for future decision making purposes. Cost of implementation is approximately $21,000 per project, implying break-even savings to justify implementation for a sample $15 million project of 0.14% of total project cost, and for projects with costs greater than $15 million, a potentially greater positive impact when compared to project cost. We expect a positive cost benefit for the Company and our customers.</td>
<td>Accepted</td>
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<td>70</td>
<td>XIII</td>
<td>Electric - Central Operations 3</td>
<td>Strengthen Substation Operations program management processes by adding project management principles in a structured way. (Conclusion 18)</td>
<td>6/09</td>
<td>1/10</td>
<td>1/10</td>
<td>Program Management Teams will be developed identifying the key positions and associated roles and responsibilities. Current Working Estimates will be developed for each program and utilized for cost control.</td>
<td>Costs and benefits estimates have remained the same since our last update. We expect an annual productivity improvement of 1% on the total SSO Capital Program cost. This would result in annual savings of $1.7 million based on the average expected annual spending levels in 2011 and 2012. Net of annual operating costs, savings are expected to total $400K annually. Implementation of this recommendation also helped us achieve our cost management KPIs related to program and project management. In 2011 we completed 100% of our KPI related projects and programs on budget, and 87.5% on schedule. We also performed 2,695 current working estimate reviews for capital projects and programs versus a goal of 1,500. We remain on track to meet these goals in 2012.</td>
<td>Accepted</td>
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<tr>
<td>73 H</td>
<td>XIII</td>
<td>Electric - Electric Operations 3</td>
<td>Implement a corporate total holistic approach to cost management. (Conclusion 6)</td>
<td>2/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Formal Cost Management Program Document or Procedure</td>
<td>This recommendation has been completed as part of the Company’s implementation of a holistic approach to cost management, discussed in Recommendation 45.</td>
<td>Accepted</td>
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<td>VII - Load Forecasting - 1</td>
<td>Analyze, and redirect as appropriate, the level of effort and sophistication applied to various load forecasting tasks and products, to better balance costs with product and user needs. (Conclusion 2)</td>
<td>6/09</td>
<td>1/10</td>
<td>1/10</td>
<td>Develop methods for shifting resources to higher value tasks and products.</td>
<td>There were no additional costs identified at this time to implement the recommendation. The Company’s forecasting groups eliminated and streamlined tasks, and in so doing, freed up resources for developing sensitivities for the Electric Long Range Plan and supporting more “what if” studies. These new sensitivities should result in a more robust planning process that further considers the impact of economic assumptions, energy policies, and changes in trends and new technologies.</td>
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<td>16</td>
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<td>VII - Load Forecasting - 3</td>
<td>Conduct an R&amp;VF review of certain aspects of its approach to forecasting. (Conclusions 9, 13, 14)</td>
<td>7/09</td>
<td>6/10</td>
<td>6/10</td>
<td>Provide the changes to our current gas forecasting process, if it is determined that changes are needed.</td>
<td>Studying alternative methods of forecasting could lead to improved accuracy of our forecasts. R&amp;VF found that incorporating the real disposable income variable in the SC 1 volume forecasting model improved the accuracy of the forecast by 0.2% for the time period studied.</td>
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<td>17</td>
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<td>VII - Load Forecasting - 4</td>
<td>Evaluate the factors responsible for consistently under-estimating 5 and 10 year peak load forecasts; assure that any bias is removed from future forecasts. (Conclusion 14)</td>
<td>7/09</td>
<td>3/11</td>
<td>3/11</td>
<td>Identify key factors causing the bias, and incorporate appropriate change(s) in revised forecasting process for electric long range plan.</td>
<td>While no additional costs to implement the recommendation have been identified at this time, consulting, modeling or software costs may be incurred in the future. A potential benefit from more accurate, but higher, longer term forecasts will be earlier identification of required capital expenditures. Implementation of this recommendation helps mitigate the risk that a consistent under-forecasting bias continues and could unduly delay required capacity additions.</td>
<td>Accepted</td>
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<td>18</td>
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<td>VII - Load Forecasting - 5</td>
<td>Expand load forecasting activities and capabilities to encompass analysis of uncertainties using sensitivity analyses, probabilistic tools or other applicable techniques. (Conclusion 18)</td>
<td>6/09</td>
<td>1/10</td>
<td>1/10</td>
<td>Incorporate sensitivity and probabilistic approaches as appropriate into future load forecasts.</td>
<td>As indicated in the completion summary of recommendation 14, the Company’s forecasting groups eliminated and streamlined tasks and in so doing, freed up the necessary labor resources to implement this recommendation. As a result, there were no additional costs identified at this time to implement the recommendation. By implementing this recommendation, the Company will be doing more “what if” studies of assessing the potential impact of new demand drivers, such as electric vehicles on infrastructure requirements, resulting in more robust planning. The analysis conducted to implement this and other load forecasting recommendations is in-line with our principle to improve continuously and seek ways to refine the demand forecasting process.</td>
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<td>VII - Load Forecasting - 6</td>
<td>Develop an improved approach to the documentation, testing, and communication of forecast criteria and assumptions. (Conclusion 19)</td>
<td>1/09</td>
<td>12/09</td>
<td>11/09</td>
<td>Prepare a document identifying the key assumptions in the preparation of the long-term forecasts and for use in Electric Long Range Plan.</td>
<td>The cost to produce these documents was minimal. The benefit of having the documents is to provide greater awareness of the assumptions and drivers that both forecasting groups use to produce their respective forecasts. It will also ensure consistency when questions are posed about the forecasts since everyone will be able to reference the same information.</td>
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<td>20</td>
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<td>VII - Load Forecasting - 7</td>
<td>Examine and implement as appropriate the efficiencies and quality improvements that might result from utilization of CECONY’s load research program, modified as cost-effective, to support load forecasting. (Conclusion 26)</td>
<td>6/09</td>
<td>9/10</td>
<td>9/10</td>
<td>Assess the use of load research data, and develop, test and implement appropriate findings in future summer appliance saturation surveys and load forecasts.</td>
<td>The Company has concluded that the utilization of CECONY’s existing load research program will provide benefit by enhancing our understanding of customer trends. The benefit of using this process to analyze growth trends of customer classes has expanded beyond the post summer analysis to any period of time. The cost to perform the research has not changed but the benefit increased beyond our initial effort to include any season.</td>
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<td>23</td>
<td>H</td>
<td>VII - Load Forecasting - 10</td>
<td>Establish a structured approach to the consideration of long-term eventualities that might significantly impact load forecasts, such as changes in trends, new technologies and new policies. (Conclusion 30)</td>
<td>6/09</td>
<td>11/09</td>
<td>11/09</td>
<td>Develop a range of load forecasts that consider pertinent long-term eventualities, for use in the Electric Long Range Plan (ELRP).</td>
<td>Using demand sensitivities results in a robust planning process and improved capital budgeting. These sensitivities for long-term peak demand forecasts ensure that a range of possibilities for growth in the peak demand are considered and that take into account factors not in existence at the time the forecast is prepared.</td>
<td>Accepted</td>
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<td>79</td>
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<td>XVI - Supply Procurement - Electric - 1</td>
<td>Consolidate duplicative Energy Management operations in the electric and gas hedging functions. (Conclusion 2)</td>
<td>8/09</td>
<td>4/10</td>
<td>4/10</td>
<td>Review gas and electric hedging group functions. Report findings and implement any changes to eliminate duplicative functions or consolidate.</td>
<td>The benefits associated with the merging of the gas and electricity hedging groups include the elimination of a section manager position and the associated reduction in labor costs by approximately $125,000. These savings are reflected in Energy Management’s forward looking budgets.</td>
<td>Accepted</td>
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<tr>
<td>80</td>
<td>H</td>
<td>XVI - Supply Procurement - Electric - 2</td>
<td>Develop a comprehensive portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans. (Conclusions 3, 7, 14)</td>
<td>2/09</td>
<td>6/10</td>
<td>6/10</td>
<td>Electricity Supply will develop and annually review and update a long term supply outlook.</td>
<td>Implementation costs will be generally low as the templates for the annual plan already exist. Going forward, the cost of updating the plan is negligible. One benefit of this long-term plan is that we have created a standard format and template for annual review and update. This will provide a means of more robust evaluation of the electricity supply outlook and forecasts, and can be used to develop plans for the Company’s electric system for different future demand and supply conditions. Additional benefits include energy cost savings that could occur if the Company identifies improvements in its energy supply operations. To the extent that there are savings from our strategic purchase decisions, those savings will be directly passed on to customers as they occur.</td>
<td>Accepted</td>
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<td>82</td>
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<td>XVI - Supply Procurement - Electric - 4</td>
<td>Identify, analyze and document all reasonable alternatives to its existing sources for both capacity and energy. Alternatives that are superior to the status quo electric resources should be implemented. (Conclusions 8, 9, 11)</td>
<td>2/09</td>
<td>6/10</td>
<td>6/10</td>
<td>Electricity Supply will develop and annually review and update a long term supply outlook.</td>
<td>This recommendation was completed in tandem with Recommendation 80. Please see Recommendation 80 for additional details.</td>
<td>Accepted</td>
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<td>7</td>
<td>Gas Main Replacement</td>
<td>15</td>
<td>IX - System Planning - Gas - 1</td>
<td>Maintain current information about CECONY's leak-prone pipe. (Conclusion 6)</td>
<td>4/09</td>
<td>2/10</td>
<td>2/10</td>
<td>Provide a final evaluation of the Company's cast iron and unprotected steel gas distribution system and develop the optimum annual replacement levels</td>
<td>In addition to tracking our commitment to replace 50 miles of leak prone pipe per year through the 2011-2013 PSC Rate Case Agreement, we have incorporated this into the corporate tracking system (Capital KPI Modifier Program) to ensure compliance. Through the capital main replacement program efforts we expect to reduce the risk of serious incidents caused by leaks.</td>
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<td>Gas Capacity Planning</td>
<td>15</td>
<td>VII - Load Forecasting - 2</td>
<td>Find a better way to forecast growth in the peak gas load. (Conclusion 8)</td>
<td>7/09</td>
<td>4/10</td>
<td>4/10</td>
<td>Revise gas demand growth forecast methodology and model.</td>
<td>Demand Forecasting reallocated internal resources while also automating and streamlining some of its functions, allowing for implementation of the new demand forecasting methodology without need for additional resources. The primary benefit of this new forecasting methodology will be the independent development of the natural gas peak demand forecast by Demand Forecasting and the energy forecast by the Revenue and Volume Forecasting section of Accounting. This more independent process with its “checks and balances” will help improve the accuracy of the peak demand forecast.</td>
<td>Accepted</td>
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<td>86</td>
<td>XVI - Supply Procurement - Gas - 2</td>
<td>Provide for more regular examination of Gas Supply’s award of supply contracts by Internal Auditing. (Conclusions 7, 8)</td>
<td>8/09</td>
<td>11/09</td>
<td>10/09</td>
<td>Schedule an audit of gas procurement in the 2010 Audit Plan</td>
<td>In 2008 we spent $1.5 billion for the procurement of natural gas for resale. By increasing the amount of review of these procurements in the annual plan, we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place.</td>
<td>Accepted</td>
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<td>87</td>
<td>XVI - Supply Procurement - Gas - 3</td>
<td>Explore applying probability-of-occurrence analysis to its supply-capacity planning. (Conclusion 13)</td>
<td>8/09</td>
<td>4/10</td>
<td>4/10</td>
<td>Develop final conclusions and recommendations regarding application of applying probability-of-occurrence to the company’s supply/capacity planning</td>
<td>While the Company concluded that the application of probability-of-occurrence analysis to natural gas supply and capacity planning is not currently feasible, it continues to seek to improve its gas demand forecasting and planning capabilities to better plan and manage the cost of natural gas to its customers. The Company gained valuable insight into the natural gas data analysis used in forecasting demand and gas supply risks.</td>
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<td>Performance and Resource Management</td>
<td>Increase the amount of stretch and put more pay at risk as part of a broad revamping of incentive compensation. (Conclusions 7, 9, and 10)</td>
<td>1/09</td>
<td>7/11</td>
<td>4/11</td>
<td>Review management compensation plan and develop 2010 and 2011 performance measures linked to compensation</td>
<td>Implementation costs were minimal as the compensation consulting studies were done as part of the Company’s normal review and assessment of compensation practices. Con Edison's current compensation program components, merit pay, variable pay, and restricted stock grant, are typical among utility and other industries. The variable pay portion of the current management compensation program places at risk a portion of an employee's compensation which must be re-earned each year through the achievement of pre-determined performance and cost management measures. The reason for having a competitive program is to have the ability to attract outside talent and for retention of competent employees. Performance targets are aligned with payouts to motivate employees to achieve the desired goals. Each year, as part of our annual review process, we review performance indicators to evaluate the effectiveness of the plan and make changes as appropriate.</td>
<td>Modified</td>
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<td>12</td>
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<td>Performance and Resource Management</td>
<td>Before the study is done and implemented, reduce the emphasis on O&amp;M expense and increase the weighting for capital expenditure performance and the operating performance measures. (Conclusions 7 and 8)</td>
<td>1/09</td>
<td>7/11</td>
<td>4/11</td>
<td>Introduce KPI measures for capital expenditure. This recommendation was completed in tandem with Recommendation 11. Please see Recommendation 11 for additional details.</td>
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<td>Performance and Resource Management</td>
<td>Develop a corporate-wide management information system. (Conclusions 2, 4, 5, 6, 7)</td>
<td>10/09</td>
<td>1/11</td>
<td>1/11</td>
<td>Determine the approach and scope of work for augmenting the Corporate Performance Indicator/Key Performance Indicator reporting system. Execute the implementation plan. The development of the trending feature for the CPI dashboard was completed at a cost of $82,000. Efficiency savings of approximately $20,000 per year continue to accrue from the development of the trending feature for the CPI dashboard.</td>
<td>Modified</td>
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<td>53</td>
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<td>9</td>
<td>Performance and Resource Management</td>
<td>Perform comprehensive resource analysis for all business units on a quarterly or semi-annual basis. (Conclusions 3, 5, 9, 11)</td>
<td>9/09</td>
<td>4/10</td>
<td>4/10</td>
<td>Establish schedules with operating groups to review short and long term resource requirements for workforce planning. In 2012, due to reduced need for splicer training based on projecting splicer attrition using VEMO, we expect to reduce the number of Splicer Instructors by two. The average cost of a splicer instructor is $115K. The cost of two instructors is $230K and the annual cost for VEMO in 2012 is approximately $110K. This would be a one year savings of $120K.</td>
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<td>54</td>
<td>H</td>
<td>9</td>
<td>Performance and Resource Management</td>
<td>Assess and monitor the productivity and cost impacts of carrying an extra trainee on some work crews on a continuous basis to achieve more efficient resource management. (Conclusion 5)</td>
<td>10/09</td>
<td>2/10</td>
<td>2/10</td>
<td>Determine annualized cost and productivity impact for use of extra trainee on a crew. Establish a uniform policy for determining the length of time for using the extra trainee on a crew. Unit cost impact of on-the-job training time for &quot;extra trainees&quot; varies by work function, and ranges from a 3.6% cost increase for the most training intensive work function studied to a smaller impact for others. Knowing the cost and productivity impact of carrying the extra trainee will provide a better understanding of cost variations and the impact on productivity, which will help in making financial decisions in hiring practices. To ensure consistency throughout Electric Operations, and to assess and monitor these impacts going forward, a guideline document to clarify on-the-job work accounting practices has been established for reference.</td>
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<td>55</td>
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<td>9</td>
<td>Performance and Resource Management</td>
<td>Conduct a root cause analysis of the upward trend in OSHA target rate in Gas Operations and prepare and implement a corrective action program. (Conclusion 7)</td>
<td>7/09</td>
<td>6/10</td>
<td>5/10</td>
<td>Determine the root cause of the upward trend in OSHA target rate in Gas Operations. Develop and implement strategies to improve Gas Operations OSHA rate. Gas Operations has seen steady improvement in its safety performance. The OSHA incident rate through August 2012 was 2.15 with 14 total injuries or illnesses. Through the same period in 2011, it was 2.64 with 18 total injuries or illnesses.</td>
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<td>57</td>
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<td>XII - Work Management - Resource Management - 5</td>
<td>Increase efforts to segregate safety from contractual issues in management / bargaining unit dialog. (Conclusion 6)</td>
<td>8/09</td>
<td>4/10</td>
<td>4/10</td>
<td>Improved bargaining unit participation in safety programs, development of union /management safety committees that effectively separate safety from other contractual issues.</td>
<td>The incremental costs were estimated at approximately $23,000 for 2010, with Phase 2 beginning in 2011 after a review of the results of Phase 1. The costs and benefits have not changed, except that they have moved one year forward. While we expected the costs to materialize in 2010, the bulk of the work did not occur until 2011, and will continue in 2012 for this pilot program. The Company expects that by implementing the Health &amp; Safety Ladder system, union / management relationships should improve and there would be some related savings due to the reduction in grievances and arbitrations. See additional benefits related to an improved focus on safety in recommendation 58.</td>
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<td>58</td>
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<td>XII - Work Management - Resource Management - 6</td>
<td>Review safety targets with the objective of adapting &quot;stretch,&quot; but attainable, levels that exceed historical averages. (Conclusion 6)</td>
<td>7/09</td>
<td>12/09</td>
<td>12/09</td>
<td>An established process to develop future goals that support the Company's commitment to safety excellence.</td>
<td>The Company met and exceeded the 2011 goal for the OSHA incident rate (1.92/2.56 goal). A OSHA incident rate goal was established for 2012 for CECONY which will continue to lead us towards the 2014 goal of 1.5. Currently, we are at 1.27 (through July) which places the Company in the right direction to meet the year end goal for CECONY of 2.21.</td>
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<td>XII - Work Management - Resource Management - 7</td>
<td>Strengthen enforcement of contractor compliance with their safety programs. (Conclusion 8)</td>
<td>9/09</td>
<td>1/11</td>
<td>1/11</td>
<td>A completed evaluation of current efforts to ensure contractor compliance with safety requirements. Identification of opportunities to enhance those efforts.</td>
<td>Approximately $10,000 in Company labor was spent in developing and implementing recommendations to strengthen enforcement of contractor compliance with their safety programs. The cost associated with revising the Contractor eHASP training module and developing the COS training module was approximately $38,000. The benefits achieved through these training courses and the implementation plan are enhanced control over contractors and their work site conditions, enhanced contractor evaluations, better written contractors’ eHASPs and increased contractors’ awareness on their eHASPs. The Contractor OSHA Rate for 2011 was 2.12 compared to a goal of 2.56. The 2012 Contractor OSHA Rate through June is 1.5 compared to the year end goal of 2.21.</td>
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<td>XII - Work Management - Resource Management - 8</td>
<td>Establish a corporate philosophy, policies and supporting guidelines for the balancing of in-house and contractor resources. (Conclusion 12)</td>
<td>9/09</td>
<td>4/10</td>
<td>4/10</td>
<td>A single philosophy and written guidelines for balancing in-house and contractor resources.</td>
<td>The HR Guidance Memo reinforced and standardized our practice that a cost/benefit analysis is performed when required to obtain the optimal mix of in-house and contractor resources. On recent example is the outsourcing of the garnishments process in Payroll. After performing a cost benefit analysis, this outsourcing solution estimates annual savings of $68,000.</td>
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<td>61 H</td>
<td>XII - Work Management - Resource Management - 9</td>
<td>9</td>
<td>Establish a corporate philosophy, policies and supporting guidelines to provide managers and supervisors with a framework to manage overtime. (Conclusion 9)</td>
<td>9/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Develop a guidance document for managing overtime</td>
<td>Implementation costs will be generally low as this is a recalibration of administration and management functions related to overtime expenses presently deployed in most operating areas. The cost of the benchmarking study was approximately $4,000. The demonstration of potential benefits is discussed in recommendation 62. The largest benefits are expected to be improved overtime cost control and increased accountability. Other benefits include the creation of a standard format for overtime reporting, analysis and control, and for high-level historical usage trends correlated to business activity. The Local Guidance Document will afford each organization greater structure in making overtime decisions while maintaining the flexibility to manage its overtime budget.</td>
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<td>63</td>
<td>XII - Work Management - Performance Measurement - 1</td>
<td>1</td>
<td>Advance the continuous improvement efforts under The Way We Work program. (Conclusions 1, 2)</td>
<td>9/09</td>
<td>2/10</td>
<td>2/10</td>
<td>Develop a plan to advance the continuous improvement efforts under the Way We Work Program</td>
<td>There were no additional costs identified at this time to develop the communication plan. The cost to develop the training programs was approximately $142,000. The benefits from these courses include basic training to employees on important analytical, cost and project management principles that are critical for managing the Company’s programs and projects. In addition, these courses will promote and develop better teamwork and group communication, and enhance customer service through improved processes and innovation. The project management course provides an understanding of detailed work-breakdown structures that support more accurate scheduling and cost estimates.</td>
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<td>64 H</td>
<td>XII - Work Management - Performance Measurement - 2</td>
<td>2</td>
<td>Include pertinent productivity improvement goals in future KPIs at various management levels. (Conclusion 3)</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Provide a measurable Productivity initiative in the form of a department KPI at the VP level</td>
<td>The utilization of KPIs is expected to help facilitate achieving the 1-2% productivity improvement per year.</td>
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<td>66</td>
<td>XII - Work Management - Performance Measurement - 4</td>
<td>4</td>
<td>Participate more actively in external information sharing efforts. (Conclusion 10)</td>
<td>10/09</td>
<td>7/10</td>
<td>7/10</td>
<td>Evaluate the need for a central approach to involvement in benchmarking efforts. Develop a process for determining which efforts the Company should be involved in and who should be the proper representative. Determine how best to share throughout the company the information obtained from these efforts.</td>
<td>Implementation required no additional costs beyond the labor to perform functions and milestones. We expect to realize savings that will exceed the cost of the initial implementation ($30,000) and annual maintenance costs ($15,000). Benefits are expected to exceed costs through the enhancement and organization of information sharing and benchmarking efforts at Con Edison to support better processes, tools and technologies and to improve decision-making.</td>
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<td>81 H</td>
<td>XVI - Supply Procurement - Electric - 3</td>
<td>3</td>
<td>Revise the performance measures (KPIs) for energy management to provide metrics and incentives that align with electric procurement objectives. (Conclusion 4)</td>
<td>5/10</td>
<td>11/10</td>
<td>11/10</td>
<td>KPIs reviewed as part of budget process.</td>
<td>No additional resources were required. The new KPI to complete and review the Company’s Long Term Electricity Supply plan increases the line-of-sight between short- and long-term planning and the resulting impact on system constraints and customer costs. These KPI modifications also increase accounting accuracy and transparency.</td>
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<td>VIII - System Planning - Electric - 1</td>
<td>Evaluate reliability programs to determine if they should be terminated earlier to release capital expenditures for more cost effective reliability programs. (Conclusion 3)</td>
<td>1/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Efficient frontier curves for selected programs indicating cost and value. A recommendation on spend level.</td>
<td>Through the development of cost-benefit profiles for distribution programs we have reduced our capital budget for electric distribution programs by $51M from our 2009 pre recommendation levels and these referenced capital budgets currently remain at or slightly below their post adjustment level. We continue to realize an annual reduction in Capital Reliability spend of $10M due to a contraction of the PILC program. Programs for critical transmission assets were analyzed for their reliability impact and cost-effectiveness, this allowed us to realize $24M in savings in 2009. Going forward funding over the five-year capital plan has been reduced for the 138kV Breaker Program, 345kV Breaker Program and Disconnected Switched Program, by $13 million, $9.2 million, and $4.4 million respectively. Two programs, the Capacitor Cable Upgrade Program with annual funding of $3 million and the Substation Loss Contingency Program with annual funding of $2 million, were shown to have limited strategic value and are no longer funded in our capital budget plan.</td>
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<td>VIII - System Planning - Electric - 2</td>
<td>Analyze networks and the 138 kV system designed to N-1 standards to determine the extent that maintenance activities can be performed at load levels less than peak load; where appropriate, incorporate maintenance design requirements into relevant design standards (Conclusion 6)</td>
<td>8/09</td>
<td>2/10</td>
<td>2/10</td>
<td>Summary report of maintenance activities during specific load levels. Summary report on opportunities to add SCADA emergency ties on auto-loops.</td>
<td>As related to the 138 kV System – N-1 Design, substations previously identified as having restricted maintenance periods have already benefited or will benefit from load relief or load transfers to provide greater flexibility in scheduling equipment outages during the entire non-summer period. As related to Auto-loops, based on the past performance of the 18 auto-loops that have manual emergency tie switches and established Company procedures regulating maintenance work, the capital expense to install SCADA-controlled or automatic switches on these 18 auto-loops is not cost justified.</td>
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<td>VIII - System Planning - Electric - 3</td>
<td>Clarify transmission planning criteria with regard to transfers used during second contingency analysis. (Conclusion 8)</td>
<td>6/09</td>
<td>11/09</td>
<td>11/09</td>
<td>Assessment of criteria</td>
<td>Improves operational clarity to stakeholders and maintains compliance with regulatory reliability performance criteria. There was minimal cost associated with performing the benchmarking effort and updating the document.</td>
<td>Accepted</td>
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<td>VIII - System Planning - Electric - 4</td>
<td>Perform a global review of all equipment ratings, input data, and time durations across the distribution and transmission areas to assure consistency and to justify and document differences. (Conclusion 14)</td>
<td>9/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Report examining equipment ratings identifying modifications needed to promote consistency, and explaining rating differences where required.</td>
<td>Provides more representative temperatures for the underground environment, which will produce more realistic equipment ratings. The benefit is that equipment is neither underated, resulting in unnecessary load relief work, nor overrated, resulting in possible equipment overloads during high load periods.</td>
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<td>VIII - System Planning - Electric - 5</td>
<td>Maintain the 2011 completion date for completion of network secondary topology updates and EPRI DEW software. (Conclusion 16)</td>
<td>7/07</td>
<td>12/11</td>
<td>12/10</td>
<td>Update load flow models to include customer secondary distributed load.</td>
<td>A comparative analysis of the former modeling method of concentrating demand at the transformer and the new distributed demand process demonstrated that refined distributed demand model resulted in fewer overloaded primary section and transformers. The analysis of the two modeling methods was completed on four Bronx networks and judged against a common load background. The approximate cost of developing these four distributed demand models was $450K; the reduction in overloads resulted in $1.8 million dollar savings in system reinforcement spending. DEW software failed to give correct and consistent results, and continued implementation would require extensive work in order to satisfy the Company’s distribution modeling needs. Alternative software products from Siemens and CYME were implemented after evaluation found them to be cost effective to complement the Company’s existing modeling process.</td>
<td>Modified</td>
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<td>29 H</td>
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<td>VIII - System Planning - Electric - 6</td>
<td>Perform a least cost system analysis that minimizes costs to customers with regard to implementation of 3G strategies. (Conclusion 17)</td>
<td>1/07</td>
<td>7/11</td>
<td>7/10</td>
<td>Assessment of 3G alternatives for load relief. Cost analysis for Flushing autoloop design. Risk assessment of network outage due to area station loss.</td>
<td>We continue to evaluate the cost benefit of new 3G designs, and will update existing cost benefit analyses of major substation projects when the service dates are closer. Long term cost benefits of new 3G opportunities were evaluated and quantified for inclusion in the Integrated Long Range Plan. The 3G cost avoidances and savings built into the Integrated Long Range Plan are forecasted to be $3.5 billion over the 20 year planning horizon. Least cost 3G designs have also been developed for the electric distribution system over the past 12 months achieving an estimated $650,000 in capital savings.</td>
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<td>VIII - System Planning - Electric - 7</td>
<td>Perform analyses to determine if peak demand can be reduced more economically than the addition of infrastructure. (Conclusion 19)</td>
<td>11/08</td>
<td>12/11</td>
<td>12/10</td>
<td>Assessment of 3G alternatives for load relief. Cost analysis for Flushing autoloop design. Risk assessment of network outage due to area station loss.</td>
<td>The Company has incorporated DSM into the existing Load Forecasting and Load Relief planning processes, the Electric Long Range Plan and has worked with NYSERDA to target DG incentives in networks with future load relief needs. DSM provides the potential to defer infrastructure investment.</td>
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<td>VIII - System Planning - Electric - 8</td>
<td>Actively pursue the economic use of SCADA controlled network mid-point feeder sectionalizing switches or circuit breakers to reduce system investment. (Conclusion 20)</td>
<td>10/06</td>
<td>1/10</td>
<td>1/10</td>
<td>Assessment of 3G alternatives for load relief. Cost analysis for Flushing autoloop design. Risk assessment of network outage due to area station loss.</td>
<td>The company plans to continue to outfit all the switches installed with SCADA during the fall of this year and during the spring of 2012. The strategic deployment of SCADA equipped sectionalizing switches results in the reduction in feeder loading experienced during a contingency. This will result in less reinforcement work to replace feeder components and, therefore, capital savings. Because SCADA operation avoids increased loading on alternate components, critical components do not require reinforcement in order to remain in service.</td>
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<td>11 Gas and Steam Planning</td>
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<td>IX - System Planning - Gas - 2</td>
<td>Evaluate potential changes in the business environment for each of the businesses; for the GBU, Strategic Planning should advise Gas Engineering regarding potential demands on the gas transmission and distribution systems occasioned by those changes. (Conclusion 16)</td>
<td>8/09</td>
<td>7/10</td>
<td>5/10</td>
<td>Identification of major factors which could shift current energy utilization more towards higher gas consumption on the distribution and/or transmission systems. Development of the plan to address the effects of these factors and update the Gas System Long-Range Plan accordingly.</td>
<td>As a result of our integrated long range planning efforts our 20 year gas capital expenditure forecast has increased by approximately $600M since the 2010 Plan. This increase is largely due to our recent expectation of additional oil conversions and public improvement investments. Through our planning efforts we have identified an additional $50 Million in savings over the 20 year horizon to help offset cost increases.</td>
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<td>37</td>
<td>IX - System Planning - Gas - 3</td>
<td>Report to stakeholders and the NYPSC on any expansion of the transmission and distribution systems required to serve winter-period electric power generation. (Conclusion 18)</td>
<td>9/09</td>
<td>9/10</td>
<td>6/10</td>
<td>Identification of factors that will affect gas supplies to generators. Development of the plan to address the effects of these factors and update the Gas System Long-Range Plan accordingly.</td>
<td>A cost-benefit analysis based on reinforcing the gas transmission system for electric generation revealed that no savings to Con Edison would be realized. Con Edison is not responsible for the capital cost associated with reinforcement associated with interruptible customers. As in past gas transmission reinforcement projects, generators contributed to the cost of the projects in order to receive additional, interruptible gas supply. The remaining costs of the projects were funded by Con Edison in order to provide additional gas to firm gas customers and to improve reliability.</td>
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<td>X - System Planning - Steam - 1</td>
<td>Identify a Steam Master Plan and incorporate within it a greater emphasis on what is happening on and to its distribution system. (Conclusion 4)</td>
<td>8/09</td>
<td>12/11</td>
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<td>The Steam Long Range Plan (SLRP) will detail short to long-term strategies with a greater emphasis on steam distribution.</td>
<td>The Integrated Long Range Plan includes estimated steam operating expense savings of approximately $1.8 billion over the 20 year planning horizon. O&amp;M savings are the result of the shutdown of the Hudson Avenue Boilers, management of the Ravenswood A-House and fuel savings from the Hudson Avenue boiler retirement, revised Steam Production Plant Operating Criteria, the minimum oil burn settlement at the Federal Energy Regulatory Commission and natural gas addition projects at the 59th Street and 74th Street Generating Stations.</td>
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<td>XIV - Project Management - Gas - 1</td>
<td>Staff a project coordination/specialist group under the Chief Distribution Engineer to assist in the execution of distribution capital projects such as the main replacement program. (Conclusion 1)</td>
<td>8/09</td>
<td>12/09</td>
<td>12/09</td>
<td>The development and staffing of project managers/engineers to support the operations if cost beneficial. If it is determined to not be cost beneficial, then the implementation of project management principles to be utilized by construction managers.</td>
<td>In 2011 we met our unit cost target of $406 per foot for our main replacement program. Meeting this target resulted in approximately $2.7 million in savings over the 2010 unit cost. Savings going forward will be dependent on the amount of projects governed by the project management group.</td>
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<td>XIV - Project Management - Gas - 2</td>
<td>Improve and expand the current project scope documentation to add sections on risks and rewards and alternative methods. (Conclusion 2)</td>
<td>7/09</td>
<td>8/09</td>
<td>8/09</td>
<td>Improved budget justification and appropriation requests indicating more detailed risks, rewards and alternative methods</td>
<td>Improved decision making process.</td>
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<td>XIV - Project Management - Gas - 3</td>
<td>Start benchmarking with other urban utilities and utilize what these other utilities are doing better to improve the CECONY program and project management of capital projects. (Conclusion 3)</td>
<td>8/09</td>
<td>11/09</td>
<td>11/09</td>
<td>Incorporate best practices from other urban utilities to improve on CECONY’s existing program and project management of capital projects.</td>
<td>The cost of performing the benchmarking study was minimal. Doing the Conceptual Packages up front has no incremental cost. Therefore, implementation benefits may include all costs avoided as a result of doing Conceptual Packages prior to budgeting and detailed design. Conceptual Packages done up front should result in fewer design and construction changes, thereby providing a cost avoidance due to project changes in the detailed engineering phase of the project or in construction.</td>
<td>Accepted</td>
<td>Completed</td>
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<tr>
<td>77</td>
<td></td>
<td></td>
<td>XV - Project Management - Steam - 1</td>
<td>Identify projects requiring the application of project management techniques through a more formal, structured process. (Conclusion 1)</td>
<td>9/09</td>
<td>4/10</td>
<td>4/10</td>
<td>The development of a departmental operation procedure that institutes a more formal, structured process for project management in Steam Operations.</td>
<td>For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that there will be 1% savings for efficiency improvements associated with project management techniques.</td>
<td>Accepted</td>
<td>Completed</td>
</tr>
<tr>
<td>78</td>
<td></td>
<td></td>
<td>XV - Project Management - Steam - 2</td>
<td>Train steam distribution operations personnel in work and project management techniques. (Conclusion 3)</td>
<td>9/09</td>
<td>6/10</td>
<td>5/10</td>
<td>The development of a successful training program on project management in Steam Operations. Evidence of training effectiveness will be demonstrated through pervasive the regular use of project management principles in the department.</td>
<td>For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that that there will be 1% savings ($30,000) for efficiency improvements associated with project management techniques.</td>
<td>Accepted</td>
<td>Completed</td>
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<tr>
<td>No.</td>
<td>Team</td>
<td>Chapter Reference</td>
<td>Recommendation (w/referenced conclusions)</td>
<td>Start Date</td>
<td>Completion Date (Est.)</td>
<td>Completion Date (Act.)</td>
<td>Deliverable(s)</td>
<td>Summary of Cost, Benefit, and Risk Analysis</td>
<td>Assessment</td>
<td>Status</td>
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<tr>
<td>83</td>
<td>H</td>
<td>XVI - Supply Procurement - Electric - 5</td>
<td>Internal Auditing should schedule more frequent audits of electric procurement decisions, documentation for entering into electric supply contracts, and daily purchase decisions. (Conclusion 17)</td>
<td>8/09</td>
<td>11/09</td>
<td>10/09</td>
<td>Schedule an audit of electric procurement in the 2010 Audit Plan</td>
<td>By increasing the amount of review of these procurements in the annual plan we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place. Auditing has not incurred any additional cost to address these audits.</td>
<td>Accepted</td>
<td>Completed</td>
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<tr>
<td>84</td>
<td>H</td>
<td>XVI - Supply Procurement - Electric - 6</td>
<td>Document processes, procedures, and guidelines for electric supply and scheduling, and for the 20 percent purchase flexibility in electric hedging. (Conclusion 20)</td>
<td>1/09</td>
<td>9/09</td>
<td>9/09</td>
<td>New Physical Electricity Scheduling Manual and associated Process Guides. Guideline for 20 percent purchase flexibility.</td>
<td>No additional costs or benefits have been incurred or realized. The Physical Electricity Scheduling Manual is being used as a reference to support evaluation of scope and required functionality of required electricity scheduling software.</td>
<td>Accepted</td>
<td>Completed</td>
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<tr>
<td>85</td>
<td>H</td>
<td>XVI - Supply Procurement - Gas - 1</td>
<td>Make finding means for increasing interdepartmental coordination an Energy Management priority. (Conclusion 3)</td>
<td>8/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Electricity Supply and Gas Supply will document actions they have identified that will improve coordination between the two departments.</td>
<td>The benefits associated with the merging of the gas and electricity hedging groups include the elimination of a section manager position and the associated reduction in labor costs by approximately $125,000. These savings are reflected in Energy Management’s forward looking budgets.</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
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<tr>
<td>88</td>
<td>H</td>
<td>XVI - Supply Procurement - Gas - 4</td>
<td>Expand Gas Supply’s range of potential capacity alternatives as it considers firm customers’ peak-day requirements for supply. (Conclusions 14, 15)</td>
<td>10/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Identify potential natural gas pipeline capacity alternatives and determine whether they are viable candidates for Gas Supply to include in the long term natural gas supply plan.</td>
<td>Offers for peaking supplies are evaluated and the least-cost supplies are selected based on established guidelines. Any cost benefits realized through these peaking supply arrangements would be passed along to the firm gas customers through the Monthly Gas Cost Factor.</td>
<td>Accepted</td>
<td>Completed</td>
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<tr>
<td>89</td>
<td>H</td>
<td>XVI - Supply Procurement - Gas - 5</td>
<td>Conduct occasional Gas Supply tests to identify potential additional types of supply arrangements. (Conclusion 18)</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Gas Supply will update their procurement guidelines to include a provision to encourage suppliers to propose alternative supply arrangements in future Requests-for-Proposal.</td>
<td>These new supply points expand the range of suppliers that can participate in the Company’s natural gas procurement activities. Any reductions in cost associated with new supply arrangements will be passed on to customers through the gas adjustment clause.</td>
<td>Accepted</td>
<td>Completed</td>
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<tr>
<td>90</td>
<td>H</td>
<td>XVI - Supply Procurement - Gas - 6</td>
<td>Keep financial and credit information for gas suppliers current. (Conclusion 21)</td>
<td>9/09</td>
<td>9/09</td>
<td>9/09</td>
<td>Gas Supply will update their procurement guidelines to include a provision that they will request current credit information from the Energy Risk Management department for all active counterparties that will be invited to respond to future Requests-for-Proposal.</td>
<td>Reduced risk of entering into transactions with counterparties whose credit rating is unacceptable to the Company</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
</tr>
<tr>
<td>91</td>
<td>H</td>
<td>XVI - Supply Procurement - Gas - 7</td>
<td>Find specific, objective ways for Gas Supply to evaluate its own performance. (Conclusion 28)</td>
<td>8/09</td>
<td>1/10</td>
<td>1/10</td>
<td>Conduct benchmarking assessments with other utilities or utility organizations to identify best practices. Analyze information received and develop potential performance criteria. Propose and implement changes to performance criteria.</td>
<td>Improvements resulting from self assessment activities have the potential to lower gas cost, extract additional value from the Company’s supply contracts, and improve the accuracy of the work. While we expect savings to result, it is difficult to estimate the magnitude. To the extent savings are realized, they will be passed on to customers.</td>
<td>Accepted</td>
<td>Completed</td>
<td></td>
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<td>92</td>
<td>H</td>
<td>XVI - Supply Procurement - Gas - 8</td>
<td>Solicit proposals for external asset management. (Conclusions 29, 31)</td>
<td>2/09</td>
<td>3/10</td>
<td>3/10</td>
<td>Conduct pilot in Summer 2010 Natural Gas Purchase Plan, for summer 2010 and Winter 2010/11.</td>
<td>In 2012, the Company executed a total of five AMAs, and as a result, gas supply costs in customer bills will be reduced by an estimated $9.7 million. The revenue received from the AMAs will reduce gas costs for customers as those benefits flow through the gas adjustment clause.</td>
<td>Accepted</td>
<td>Completed</td>
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Appendix C: Summary of Implementation Actions, by Team

**Team 1 – Electric Long Range Plan**
Executive Sponsors: Luther Tai, John Miksad and John McAvoy

Recommendations: 1, 2, 3, 4, 5, 21, 22, 34, 39, and 42

**Recommendation Number: 5**
Develop a comprehensive vision and 20-year master plan for the electric system.
(Conclusion 8, 9)
Team Lead(s): Katherine Boden/ Tim Cawley

**Summary of Implementation Actions:**

This recommendation is complete.

We developed a comprehensive Electric System Long Range Plan (ESLRP or ELRP) that will serve as our roadmap for the next 20 years. Our Electric Long Range Plan, as is the case with our other long range plans, is dynamic in nature, and is a living document. As such, we will update it periodically to keep it current and make the necessary adjustments as appropriate. In our plan, we describe the uncertainties we will face, and we have identified signposts that will be monitored and reshaped as circumstances change. We expect to update our plans as fundamental changes occur in our operating environment.

The ELRP provides a strategic framework for implementing our plans to manage demand and supply, invest in our infrastructure, provide environmental stewardship, and serve our customers at a reasonable cost.

Costs to develop the ELRP totaled $2.2 million, when including internal and external labor. Through this development process, we were able to establish a platform by which we can measure customer and business needs, risks, investments, and other key drivers across common assumptions and longer-term timeframes. This shared platform increases transparency and gives direct line of sight to customers’ bills. It is critically important to us that we optimize the management of component maintenance, repair, and replacement decisions to minimize cost impact to our customers.

As a result of these optimization and efficiency efforts, we expect to experience $3.1 billion in cost avoidances and savings over the 20-year planning horizon, as compared with traditional approaches. In addition, the plan outlines potential opportunities for regulatory, tax and related reforms and utility ratemaking approaches that would increase the relative
value of electric service. Historically, Con Edison developed 10 and 20 year infrastructure plans for its electric transmission and distribution systems. These plans focused on ensuring that the systems had sufficient capacity to reliably meet customer energy requirements, and were based on stringent design criteria. The ELRP goes beyond that traditional approach by effectively integrating transmission and distribution system infrastructure plans with non-infrastructure related elements of our business, such as demand side solutions and renewable resources, into one comprehensive plan. In addition, the ELRP includes a supply outlook, because the cost of supply is a major component of our customers’ bills.

Through this comprehensive planning process we gained a deeper understanding of the impact of various programs and initiatives on our customers’ bills. The long range plans were developed in such a way as to provide a clear line of sight between our initiatives and customer bills. We are heavily focused on ensuring that we provide energy services at reasonable prices.

Cost considerations are a major part of our planning process, and we’re continuously looking for ways to do things better. Our strategy is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, and ensure employee and public safety.

We strive to minimize customer bills and have outlined in the ELRP several programs and initiatives to manage our infrastructure costs as well as to work directly with customers to manage their energy expenditures. We will continue to make every effort to keep our transmission and distribution rates down; nevertheless, market and policy forces outside of our control will continue to affect our customers’ bills.

As discussed throughout our ELRP, the objective to better manage costs to our customers is a challenge, but one which we intend to pursue and achieve. We will continue to explore and implement ways to reduce rate and bill costs for our customers and operate our system in the most cost efficient way possible, while delivering the benefits of safe and reliable electric service to customers in an innovative and environmentally responsible way.

As we expand and invest in our infrastructure over the next 20 years to meet the expected growing customer energy requirements, we will continue to manage our existing assets to implement better designs, make better purchase decisions, and better manage our inventory so that we can provide maximum benefit for our customers at the most reasonable price possible.

Our planning process began with a forward looking assessment of customer needs and the definition of strategies for how we will meet these needs in light of key uncertainties. The first step was to develop forecasts for electricity demand. We made assumptions regarding
potential environmental and regulatory requirements, economic trends, and possible technological advances to develop three forecasts for potential customer demand: a High Case, Plan Case, and Low Case. We used the Plan Case demand forecast to develop the infrastructure projects and programs in this plan and identified signposts that we will monitor to test and adapt our plan in the future.

As discussed in the ELRP, our goal is to manage our existing infrastructure, and expand it as required, in a cost effective manner. The ELRP details initiatives which challenge and fundamentally change key aspects of our current design criteria, moving us from a prescriptive and deterministic engineering design basis to one that is driven by a probabilistic approach. This new approach utilizes advanced analytical methods to maintain high levels of reliability and risk reduction with lower capital investment. We will continue to actively integrate targeted demand and supply side management programs, innovative designs, advanced technologies, as well as traditional designs to implement tailored, “best fit” solutions. And we will continue to enhance our asset management practices to optimize maintenance expenditures, effectively moving from a time-based to a condition based approach.

We also initiated a comprehensive and quantitative approach to investment optimization for this plan. To evaluate the impact of specific programs and initiatives over long timeframes, we developed a projects and programs model to facilitate development of the ELRP. This model encompasses the ELRP’s 20-year planning horizon and is used to measure the expected benefits of potential projects and programs on the basis of cost, performance, and risk, as follows:

- **Performance**: measures include contribution to transmission and distribution system reliability and environmental impact, including reduction in greenhouse gas (GHG) emissions as well as other environmental savings such as SF6 reductions throughout the system.
- **Cost**: measures include capital and Operations & Maintenance (O&M) expenditures and savings as well as projected rate and bill impact of those investments.
- **Risk**: this measure is consistent with CECONY’s enterprise risk management (ERM) process. As part of our plan to mitigate the ERM risk of a prolonged, large-scale network outage, ELRP distribution risk reduction is measured based on the network reliability index.

The forecasted capital investments were each quantified in terms of their incremental impact on the performance, cost, and risk characteristics of the CECONY electric system. Outputs from this model were used to show the accrued benefits and associated costs in the ELRP.

Over the course of our ELRP, we intend to maintain our current levels of reliability while reducing system risk in less asset intensive ways, such as through the implementation of innovative third generation (3G) designs. This newest generation of designs leverages asset
sharing approaches and is enabled by enhanced system monitoring and advanced underground switching. 3G designs enable us to defer or minimize the investment requirements of new substations, increase asset utilization, reduce cost and improve the performance of our system.

In addition to implementing new design concepts, we will employ a more integrated approach to overall system investment. Various demand and supply management programs will reduce demand on the constrained parts of our system, thus reducing infrastructure expansion and reinforcement expenditures. These solutions will apply targeted demand and supply side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas.

The need to maximize utilization and performance of our existing assets and to optimize maintenance expenditures makes strong and effective asset management essential. An effective asset management program affects maintenance patterns, repair and replacement decisions, as well as overall electric system planning and design. Greater precision in identification of the right time to add or replace an asset allows the best directed use of capital and operations and maintenance expenditures. In addition, information on operating conditions allows planners and operators to optimize system configurations when evaluating network reinforcements and replacements.

We use various methods and tools to monitor, analyze, assess and control our assets to obtain optimal performance of our electrical components, asset classes and overall system. The information we capture, trend, and analyze allows us to evaluate and compare the performance across various components or asset classes so that we are targeting our programs in the right places and, therefore, optimizing what we spend on our asset maintenance, repair, and replacement decisions. As we add more advanced monitoring on our components, we will be able to continue to move away from time-based to condition-based maintenance. By gathering and analyzing data from in-field sensors, we are better able to understand performance trends on specific asset classes. This may allow us to alter maintenance cycles, increase the life of various components, improve the design of specific assets, and predict and prevent failures.

In tandem with ELPD development, we established an ongoing long range planning process to share expectations, such as those around business-environment changes and the impact of evolving public policies, with our stakeholders and to provide context for our investment forecasts. As direct results of this effort, we have developed 20-year long range plans for our electric, gas (see Recommendation 36), and steam systems (see Recommendation 38), and we have improved our annual business planning processes to link our near-term goals and work plans to our long-term objectives (see Recommendation 1).

We incorporated customer and stakeholder input into the plan, and we continue our outreach efforts to discuss the ELPD with our stakeholders, internal and external, to communicate the results of our efforts, and to get their input. We're reaching out to
discuss the impacts of our plans on our customers, including discussions of key changes from current practice, our vision for the future, and our customers’ bills. We will continue to solicit input and feedback from our stakeholders. We continue to communicate our plan with stakeholders. Our Electric Long Range Plan is supported by Appendices and Assessment Documents. ELRP Appendices detail our demand and energy forecasts, supply outlook, and key distribution asset management metrics. The Assessment Documents provide an in-depth explanation of our assumptions and strategies for Energy Efficiency and Demand Response, Distributed Generation, Advanced Metering Infrastructure, Electric Vehicles, and New Transmission opportunities and evaluation.

By using this plan, we are now able to link our short-term plans to our long term goals, to evaluate the impact to our customers when comparing different levels of investment, and to articulate the challenges we’ll have to overcome in the coming years and decades. Our supply and energy forecasts were analyzed in a framework that examined customer demands and changing technological, economic, and societal drivers, and different scenarios were developed to account and plan for changing conditions.

We are communicating our Electric Long Range Plan internally and to external stakeholders, and we have posted our ELRP and its supporting documents on the Con Edison corporate website (www.coned.com/publicissues).
Recommendation Number:  1
Improve the planning process. (Conclusions 1, 2, 3, 4, 5)
Team Lead(s):   Nicholas Colonna

Summary of Implementation Actions:

This recommendation is complete.

We have taken significant steps to improve our business planning processes and to link our short-term planning efforts to long range strategies, goals, and objectives. Our annual business planning process has always called on our managers to balance competing priorities in this respect, and guidance for the development of the 2011 annual business plans has introduced new practices and resources.

Prior to implementation of this recommendation, organizations in Con Edison worked on business plans that, while aligned in focus and theme, presented different levels of detail around strategies and visions. The outline and structure of each also varied.

Through implementation of this recommendation, annual business plans are now being developed according to a consistent format and structure, and include standardized supporting materials. New guidance for the 2011 business planning process establishes outline for each business plan, a standard level of detail and content, and required linkage to long-term planning efforts.

Over the last year, we have improved the annual business planning process by making a number of changes, most notably by utilizing the outcomes and goals of our long range planning efforts and our enterprise risk assessments. These outcomes from the long range planning process, including vision statements and corporate strategic objectives, have provided business units with more focused direction regarding the corporation’s vision, mission, and strategic goals and objectives. These outcomes have also served as key drivers and enhancements to an organization’s annual business planning process.

While business plans are developed from a bottom-up approach, alignment for annual business planning begins at the corporate level. As established by guidance from Con Edison’s Chief Financial Officer, the development of annual business plans will be structured to address the Company’s strategic objectives in meeting many competing business priorities with respect to short-term and long-term operating performance, safety and reliability, operating efficiency and flexibility, and risk management objectives.

Long range business plans for Con Edison’s electric, gas, and steam businesses link the short-term focus of the annual business planning cycle and the long term objectives and goals of the Company. Progress towards achieving these goals are then assessed and measured in the annual business planning process.
The Company’s corporate instructions require guidance be given each year in the areas of budgeting and financial performance measurement including a schedule that identifies organizations and their responsibilities in submitting budget information. Prior to 2011, there was less emphasis with linking the annual business planning cycle and the long term objectives and goals of the Company. In addition, budget submission materials were less standardized across all business units which lessened the unity of meeting the overall strategic objectives of the Company. The annual business planning process for 2011 has been enhanced by adding linkage to the long range business plans and addressing key elements in the process such as:

- the priorities of the business that the annual business plan needs to reflect;
- the elements of the annual business plan submission, including standardized templates as appropriate;
- specific information or directions for each business unit; and,
- a timetable for the annual business plan process.

Development of the annual business plans has been standardized with uniform guidelines and templates that are followed by all business units. To standardize the elements of the annual business plan submissions, an outline for each annual business plan is provided to each business unit. This outline defines the following main points:

1) An executive summary that addresses the challenges and competing priorities that these business units face in meeting their goals and objectives.

2) A vision statement for 2030 and long-range strategy initiatives with progress status.

3) Support for cultural transformation, including identification of planned activities that promote the Company’s cultural imperatives.

4) Descriptive work plans that are designed to achieve those priorities. The work plan must first demonstrate that the right work has been proposed for the year. This demonstration could be made by a prioritization of projects and programs based on business goals. Second, the work plan must identify and quantify efficiencies to be achieved in implementing the work proposed for the year including the work prioritization method and summary results.

5) Proposed measures for the success of the work.

6) An enterprise risk management update and discussion of resources committed to mitigate risks, cost of risks, and quantified dollars in projects devoted to specific risks.
After meetings with the CEO in August and the CEO and CFO in September, a preliminary combined business plan will be presented to the Finance Committee of the Board of Trustees at its October 2010 meeting. The final annual business plan will then be presented to the Board of Trustees for review and approval at the November 2010 meeting.

The main benefits of implementation are greater alignment of objectives and goals across business units, and stronger linkage of short-term to longer-term strategies. In addition to these benefits, business plan submissions are now required to identify and quantify cost savings, productivity and efficiency initiatives in operations that could contribute towards lowering customer rates.
Recommendation Number:  2
Take the ERM process associated with operating risks to the next level. (Conclusion 7)
Team Lead(s):   Rich Muzikar

Summary of Implementation Actions:

This recommendation is complete.

To fully address the scope of this recommendation the Company’s Enterprise Risk Management (ERM) department has expanded its roles and initiatives. The Company engaged PricewaterhouseCoopers (PwC) to evaluate Con Edison’s Enterprise Risk Management program related best practices in an effort to bring it to the next level.

Taking ERM to the next level requires the expansion of risks being assessed and managed. The Company, in conjunction with PwC, developed a new ERM methodology that expands the total population of risks by identifying and prioritizing risks at the department level. Based on the current status of mitigation efforts for such risks and defined risk goals, additional risk mitigation measures and a mitigation action plan may be developed as appropriate. Mitigation plans for each risk are prioritized. These action plans will be integrated in the annual budgeting process and long-range planning.

Based on PwC’s recommendations, the Company’s ERM department has completed two Departmental Risk Profile pilot programs and is expanding this newly adopted methodology across the Company. A comprehensive Departmental Risk Profile Plan has been developed. The plan details participating departments and a schedule of completion targeted to a March 2011 deadline. ERM will facilitate the development of risk profiles across all organizations. These risk profiles will provide a detailed view of departmental risks beyond the existing Operations and Administrative risks identified in the current ERM program. This approach takes risk management to the next level by identifying significant risks in each department, developing mitigation actions plans, and linking risk mitigation action plans to budget allocations and long-range planning.

The Company has also purchased a new risk management system from CURA Software. This system will:

- Improve monitoring of risks and the projects/programs committed to reduce risk.
- Track an increasing number of risks, including those identified during development of Departmental Risk Profiles.
- Improve quantification of risk assessment.
- Enable association of key risk indicator data to individual risks, monitoring effectiveness of risk mitigation.
- Improve risk reporting functionality.
- Provide an executive dashboard which will highlight risk data.
- Serve as a central repository and data housing solution.
In order to identify best practices for ERM integration into budgeting and planning activities, Con Edison independently benchmarked with several companies who are known to have mature ERM programs.

Supplementing the ERM effort, the Capital Investment Optimization model was included as part of evaluation measures in the 2010 budget process. Risk mitigation is one of the factors that are considered during the evaluation of proposed projects. This model assists in evaluating the impact of projects on enterprise risks and promotes alignment of the Company’s project planning with its corporate strategic objectives.

The total cost to implement this recommendation was $214,200. This includes the cost to procure the services of PWC and the purchase of ThinkTank software, an online discussion facilitation tool. While exact dollar savings cannot be quantified, we believe the value of an expanded ERM program significantly reduces the probability of a risk event. The following qualitative measures indicate adequate benefits to warrant the implementation action:

- An expanded risk universe that includes both enterprise-level risk and departmental risks;
- Improved prioritization of resources (both O&M and Capital);
- Increased focus on risk management by providing a structured approach of risk profiles;
- Utilization of inherent and residual risk concept;
- Establishment of risk goals;
- Development of action plans for risk mitigation;
- Increased ability to monitor NERC/FERC compliance;
- Improved coordination of emergency management plans tied to risks.
- Improved tracking of risks through key risk indicators.
Recommendation Number:  3
Define the role of the Strategic Planning Unit. (Conclusion 6)
Team Lead(s):  Gurudatta Nadkarni

Summary of Implementation Actions:

This recommendation is complete.

The Company has taken several steps to define the mission and role of the Strategic Planning group. The Company hired a Vice President of Strategic Planning two years ago and recently increased the staffing level from six to eleven.

After reviewing the findings and recommendations of the PSC Management Audit and the current role of the Strategic Planning group, Strategic Planning conducted benchmarking with other large utilities to learn about the roles undertaken by their Strategic Planning organizations. The Vice President of Strategic Planning interviewed the leaders of Strategic Planning groups at six other utilities. Industry research was conducted as well. We found a wide spectrum of scope / roles and hence, integration of corporate thinking into the planning efforts at these companies. We identified the need to strengthen top down direction setting and a need for portfolio optimization.

Following the gathering of external benchmarking and research, the VP of Strategic Planning solicited feedback from Con Edison’s senior officers as to their opinions on what the role of the Strategic Planning organization should be. This feedback and the results gathered through the benchmarking study were used in refining the role and scope of the Company’s Strategic Planning organization.

Strategic Planning’s redefined role includes facilitating corporate direction setting, standardizing plan development and integration with the corporate strategy, leading cross functional business integration, and tracking progress. Strategic Planning will shepherd processes for delivering key corporate initiatives based on a common understanding of industry trends, anticipated business scenarios and business opportunities / threats. As an overseer of the long range planning effort, Strategic Planning will ensure that the long and short-range plans of each corporate organization align with the corporate strategy and will set common goals, assumptions and structure for all the plans.

The costs associated with implementing this recommendation consisted of benchmarking, research, analysis, and meetings with internal Company officers. This equates to approximately $75,000 based on labor costs and subscriptions to research databases. The benefits of refining the role of Strategic Planning include an improved alignment of capital investment and operational spend with defined corporate priorities. The savings are expected to exceed the $75,000 cost incurred.
Recommendation Number: 4
Revisit the subjects investigated by the interdisciplinary teams. (Conclusion 6)
Team Lead(s): Gurudatta Nadkarni

Summary of Implementation Actions:

This recommendation is complete.

Con Edison uses interdisciplinary teams to address business issues in a way that brings broader thinking to current challenges and provides opportunities for personnel development and cross-functional thinking. Key areas of focus, teams, and missions are based on strategic priorities identified during the Company’s annual strategic planning process based on a common understanding of industry, policy (national, state, and local), customer, and technology trends. At the time of the Management Audit, Con Edison’s Strategic Planning group facilitated four interdisciplinary teams, with the following missions:

- **Gas Pipeline and Storage**: conduct an initial assessment to identify specific viable gas pipeline and storage projects that provide potential for greater reliability and cost savings for gas and electric customers.

- **Electric Transmission**: conduct an initial assessment to identify specific viable electric transmission opportunities and develop an appropriate business plan.

- **Solar Photovoltaic (PV)**: conduct an initial assessment of a regulated business response for solar resources and evaluate the competitive businesses ability to provide solar resources at a competitive cost.

- **Regulatory Construct**: develop an initial assessment of possible future industry models and regulatory constructs that could support such models. Potential future models should be able to deliver clean, affordable, reliable, and secure power to our customers, meeting their needs as well as the needs of other stakeholders.

Liberty recommended that Con Edison revisit whether the individual missions of these teams were overly narrow (e.g., solar photovoltaics as opposed to a wider range of technologies), or overly broad (e.g., develop a long range vision of industry structure and the role of the regulated utility).

Strategic Planning evaluated the process for launching interdisciplinary teams in order to:

1) Determine the optimal focus and scope for the teams
2) Improve the process by which interdisciplinary teams are created

_Determining the Optimal Focus and Scope for the Teams_
Strategic Planning revisited previously launched teams and addressed concerns regarding scope determination. It was determined that, going forward, the preferred approach will lead to some teams with a narrow scope while others, by nature of what they focus on, will have a broader scope. The teams evaluated in the Management Audit fell into both categories.

The narrow scope teams included:

- **Gas Infrastructure Investment**: Given the high price of natural gas and its pressure on our customer bills, the Company launched a team with a more narrow focus to look at gas infrastructure investments that could result in better access to cheaper natural gas resources for our customers.

- **Electric Transmission**: Given the high cost of supply and its pressure on our customer bills, the Company launched a team with a more narrow focus to look at transmission investments that could result in better access to cheaper generation resources for our customers.

- **Solar PV**: Strategic Planning had done a pre-scan of the renewable space and came to the conclusion that the two technologies that could provide renewable energy sited downstate were solar PV and offshore wind. The Company saw offshore-wind as a large effort to be evaluated by LIPA, NYPA, CECONY and others given the complexity, scale and cost of the resource. Since solar PV is a more mature distributed rooftop technology, the team focused on understanding the economics, ease of development, and impact to the grid. The team also looked at the most efficient way to expand the market.

On the other hand, the regulatory construct team was launched with a broad focus because rate pressure has a broad range of sources (e.g., commodity costs, environmental requirements, etc.) and the team was focused on understanding those cross-cutting issues.

**Conclusions of the Teams**

- **Transmission**: The interdisciplinary team came to the conclusion that most of the projects under consideration in 2008-2009 failed to meet the cost-benefit requirements (i.e., costs of transmission projects exceeded expected benefits), but decided that an ongoing evaluation of transmission projects is essential. One such project is now being evaluated. The ongoing work of this team aligns with the long range planning common goal of ensuring adequate access to lower-cost supply for our customers.

- **Gas Infrastructure**: The interdisciplinary team effort identified infrastructure into New York City that would provide access to cost advantaged shale supplies in the Marcellus Shale region. This has resulted in the Company’s support of a new header into New York City to be built by Spectra Energy. The work of this team also supports the long range planning goal of ensuring adequate access to lower-cost supply for our customers.
• **Solar PV:** The team concluded that given industry projections of deep solar-equipment cost reductions over the next five years, current cost-barriers to solar installations will erode. The team also concluded that while competitive players have an important role to play, the market may need utility ownership to promote smaller scale installations. Thus, the team recommended that the Company implement a solar PV pilot to get more experience in promoting solar installations and to identify the potential impacts on our grid. In 2009, Con Edison filed with the PSC a petition for a solar pilot that is no longer under consideration.

• **Regulatory Construct:** This team studied regulatory alternatives in different jurisdictions, and concluded its effort by summarizing regulatory constructs elsewhere. The findings of these teams have formed the basis for other efforts related to rate/regulatory issues.

**Improving the Process by which Interdisciplinary Teams are Created:**

**Before:**
Prior to the implementation of this recommendation, Strategic Planning would identify key industry, policy, customer, and technology trends with feedback and guidance from the Corporate Leadership Team (comprised of the Company’s senior leaders). Next, a set of strategic priorities were identified to meet reliability, cost, environmental and other business-associated needs associated with the selected developments. Interdisciplinary teams were launched to drill down and, where appropriate, execute on these priorities.

**After:**
The Company has initiated new strategic and long range planning processes. They are now explicitly tied to each other.

During the strategic planning process, key industry trends and their long term implications are identified. A consistent view of key assumptions such as economic/population growth, commodity pricing, environmental policy, customer behavior, and technology evolution is developed. These assumptions are then incorporated into the long range demand forecasts for each commodity and help formulate a view of infrastructure solutions available/needed to meet our customer needs. Each commodity’s engineering design group then develops a long range capital investment plan. The resulting portfolio of projects/programs and their financial impact on customer bills are then evaluated through an iterative process to identify priorities that could result in adding the most customer value (e.g., lower cost, greater reliability, evolving customer needs, etc.). Once these priorities have been established, interdisciplinary teams will be launched where cross-functional skill and/or cross-organizational interactions are needed. The new process has a more direct tie to the actions required to deliver on our long range plan.
As oversight, the Planning Committee of the Board of Directors will periodically review (at least on an annual basis) the Corporate Strategy, long range plans, key sign posts and the progress of key corporate initiatives.

**Additional Actions: Initiation of New Interdisciplinary Teams**

Con Edison has recently launched the following interdisciplinary teams:

- **Cost management**: A corporate effort on cost management focus was launched to enhance operational efficiencies and capital effectiveness which would result in lower delivery costs to the customer. This team’s focus is consistent with the Company’s efforts to mitigate customer bill increases.

- **Electric Vehicle Readiness**: A team has been launched to ensure that the customer experience for early adopters of electric vehicles is positive. This team is examining customer expectations and needs with respect to electric vehicles. Supporting electric vehicles is important since they are expected to lower customer transport costs in the near future while lowering carbon emissions significantly. This team is focusing on preparing the Company to meet evolving customer needs, as discussed further in the Company’s Electric Long Range Plan (ELRP).

Costs to reevaluate the ongoing interdisciplinary teams and to improve the strategic planning process were not significant, and included use of Company resources and payment for supporting external services/products (e.g. research reports).

Future actions of the interdisciplinary teams are expected to yield benefits to customers and the Company. While the exact benefits of these efforts will become evident only after successful implementation, the insights and results delivered by these teams will likely result in lower supply cost for customers, enhanced ability to deliver clean resources, and technology solutions that result in capital effectiveness and operational efficiency.

Other benefits of future interdisciplinary teams include development opportunities for employees and cross-functional cooperation and thinking. Interdisciplinary teams will bring out the necessary expertise from various parts of the Company to provide strategic solutions to multidisciplinary issues.
Recommendation Number: 21
Aggressively move forward with the major study planned by Market Research on efficiency potentials and include a special focus on efficiencies that can be targeted to specific networks. (Conclusion 28)
Team Lead(s): Rebecca Craft

Summary of Implementation Actions:

This recommendation is complete.

The Company partnered with an outside firm, Global Energy Partners (Global), to conduct a significant energy efficiency market potential study. This study analyzed short- and long-term projections of energy efficiency potential in the Company’s service territory. Extensive surveys and audits were carried out onsite at customer locations and online to gather accurate and current building equipment and process data.

The major benefit of these types of studies is that we receive intelligence identifying the demand side management (DSM) opportunities available to reduce both electric energy consumption and demand. To the extent these opportunities materialize, the need for capital infrastructure spending may be reduced.

In the coming months, the Company will be analyzing the results of both this study and a prior one completed in 2008 for demand response. These studies, system and network needs, and the available and proposed efficiency, demand response and ancillary services programs will be reviewed and evaluated to examine what demand reductions might be achieved with existing and new energy efficiency and demand response initiatives. The in-depth knowledge of energy use and efficiency potential in the Company’s service territory gained from these studies can be used to build, refine and target demand side management programs.

Permanent reduction in energy consumption and peak demand achieved through efficiency programs sponsored by the Company and other agencies can reduce strain on the transmission and distribution (T&D) system, allowing for investment deferral, and reduced power purchase requirements. To the extent possible, the Company will target energy efficiency programs within its system, in order to realize such benefits for the T&D system. These programs, targeted to load areas where transmission and distribution upgrades including transmission lines, substations, network load transfers and distribution feeders are proposed, may defer these load-relief investments through firm load reductions. The information from the study combined with the callable load study and analysis of system needs promotes the effective use of demand side management to address these needs.

As discussed further in the Company’s electric long range plan (ELRP) currently under development, we will continue over the next 20 years to seek to integrate less traditional, but still well-proven, mechanisms to further the goals of safe, reliable, and affordable
service that minimizes our environmental impact. Demand side management (demand response and energy efficiency) may defer or eliminate the need for expensive capital infrastructure, while at the same time reducing green house gas (GHG) emissions and enhancing reliability.

The cost of the energy efficiency study was $825,000 and was funded in Case 07-E-0523 for the 2008 – 2009 rate year. All efficiency programs are subject to a Total Resource Cost test and the study helps us design better programs and address barriers to demand side management.
Recommendation Number:  22
Evaluate options to enable the consideration of current and future load curtailment initiatives, both at CECONY and NYISO, for dependable network demand reduction. (Conclusion 29)
Team Lead(s): Rebecca Craft

Summary of Implementation Actions:

This recommendation is complete.

The Company developed and implemented several peak-shaving programs during 2010.

Results from summer 2010 performance were measured, and the Company discussed analytical results in its December 1, 2010 report titled Evaluation of Program Performance and Cost Effectiveness of Demand Response Programs as submitted to the PSC. The Company concluded that results from evaluation of peak load shaving programs during the 2010 summer period were inconclusive due to low customer participation rates.

Total costs for all Peak Load Shaving Programs during the 2010 program year were $985,000 or approximately 4% of the projected two year costs of $22 million. These costs are reflective of program start-up and low participation, but should increase as the program matures over the next few years.

The peak load shaving programs are not mature, and had limited customer enrollment. As a result, there is not enough current information to evaluate whether the programs are either cost effective or feasible for operation. The pilots are currently expected to run through the end of 2012 and at that time we will have a better understanding of the potential for all peak shaving programs. However, we will continue to evaluate each pilot and program on an annual basis and adapt the programs as appropriate.

Based on 2010 program experience, the Company has refined these programs and is deploying these revised programs in 2011. The refined programs saw considerable increase in enrollment in 2011. Details on the progression are explained below.

Summary of Programs
On June 1, 2009, the Company filed its Assessment Of The Potential For Cost Effective Demand Response By Consolidated Edison Company Of New York, Inc. (Order Instituting Proceeding, issued February 17, 2009, in Case 09-E-0115). As part of this filing, the Company proposed a portfolio of four Demand Response (DR), peak-shaving programs that focused on load curtailment.
Following a collaborative of interested parties that examined the proposed programs, the Commission approved the following four programs in October of 2009:

- Commercial System Relief Program (CSRP)
- Critical Peak Rebate Program (CPRP)
- Residential Smart Appliance Program (RSAP)
- Network Relief Program (NRP)

The approved programs target both the commercial and residential markets in New York City (NYISO Zone J).

**Commercial System Relief Program (CSRP)**
The Commercial System Relief Program was approved as an ongoing program and is open to participants in Zone J who can curtail load or bring on certain emergency generation to reduce their demand by a minimum of 50 kW individually, or 100 kW through aggregation, with a minimum of 24 hours notice before a planned event (a day-ahead forecasted load level that is at least 92.5% of the Company’s forecasted summer system peak). Participants received capacity payments based on NYISO capacity auction pricing. Participants also received monthly delivery payments of $3 for each kW pledged via non-renewable generation and $5 for each kW pledged through curtailment and renewable generation.

To prevent participants from receiving incentive payments from more than one capacity based program, customers participating in the CSRP were not permitted to enroll in other capacity based programs such as the NYISO Special Case Resource program. Enrollment in CSRP was required for the entire summer peak period, June through September. The Company could require customers to participate in a maximum of ten demand response events during a summer peak period. Each event could be called for up to an eight hour period between the hours of 11 am and 7 pm. During summer periods that included more than five events, the delivery payment was doubled for each of the months including and following the fifth event. During summers when more than ten events were called, or called outside the period of 11 am to 7 pm, participants received bonus payments of $1/kW for each hour of each event in which they participated.

The CSRP has environmental and performance requirements, including a 20 percent cap on emergency generation enrollment.

**Critical Peak Rebate Program (CPRP)**
The Critical Peak Rebate Program was approved as a two-year pilot for 2010 and 2011, and it targets all customer classes. Customers who could reduce their demand by at least 1 kW during events based on 92.5% of Company’s forecasted system peak were eligible to participate. Participants who reduced their demand by at least 1 kW and up to 24 kW received a payment of $1 for each kilowatt reduced based upon the average kW provided in the two highest hours in which load relief was provided. Participants who reduced 25 kW or
more received a payment of $1.50 for each kW reduced based upon the average kW provided in the two highest hours in which load relief was provided.

Customers participating in the CPRP were not permitted to enroll in other capacity based programs such as the NYISO SCR Program. Enrollment was required for the entire summer peak period, June through September. Participants were given notification similar to the CSRP for forecasted and emergency events.

**Residential Smart Appliance Program (RSAP)**
The Residential Smart Appliance Program was approved as a pilot program. The objective of the Company’s Residential Smart Appliance Program is to extend the ability to participate in demand response to a wide cross-section of residential customers in the New York City area. The program was to be activated by Con Edison when the day-ahead forecast was 92.5% of the system peak, or greater than the summer forecasted peak.

Enrolled participants will receive a free home energy management system with installation and technology that allows participants to reduce energy demand. In exchange for participation (June through August), Con Edison will turn off certain home electric equipment enrolled in the program. Participants can manually override the Company’s request for their personal comfort and convenience during these times. Participants in all test hours, and at least 80 percent of event hours, will receive an end of season payment in the amount of $10 for each enrolled wall or window air conditioner, and $10 for the combination of other enrolled appliances. There is a minimum of 2 room air conditioners required to participate in the program.

**Network Relief Program (NRP)**
The Network Relief Program was designed to target specific networks which have a particular need for system relief. As proposed, the program anticipates issuing Requests for Proposals from individual customers and aggregators to provide specified quantities of MW relief during certain hours, for an agreed number of years. The purpose of the program is to obtain long term commitments for load shed during regular peak periods on specific system networks. This would allow the Company to incorporate more efficient energy utilization into its resource planning, and defer system capacity upgrades which would otherwise be required.

**Evaluation of Options: Discussion of Results**
While the program managers implemented several marketing strategies to promote these programs, for example, the Company did considerable program marketing for the two largest programs, the Commercial System Relief and Critical Peak Rebate Programs, these peak shaving programs had very limited enrollment due to, among other things, program design.
The Commercial System Relief and Critical Peak Rebate programs received significantly lower 2010 enrollment than anticipated, leading to a Company assessment of alternate design options. Though program participation was limited in the 2010 program year, the limited enrollment provided important information about the market and the programs’ design. CSRP and CPRP program feedback obtained from active collaborative stakeholders indicates that participating in the number of events, and maintaining participation over the required hours, was difficult.

In addition, for RSAP, identifying, procuring and installing the required program technology took longer than anticipated, and installation of this equipment continues. Due to the economic downturn and load growth in the networks declines no networks or load areas were identified for additional capacity or distribution reinforcement in conjunction with the NRP program in 2010. At this time, a potential aggregator for the NRP program has been identified for the NRP program and discussion of potential program design and associated costs have commenced.

The Company’s September 23, 2010 petition for Approval of Changes to Demand Response Programs, proposed the re-design of these programs to be more effective, to reduce barriers for enrollment, and to make customer participation easier. These design changes are intended to increase enrollment, improve response to events, leverage NYISO enrollment, and make it easier for customers to participate in these programs. The petition details changes designed to streamline programs, make them more consistent, and to maximize peak load shaving program benefits.

The Company’s September petition proposed peak load shaving program design changes as highlighted below:

- For CSRP and CPRP:
  - Permit participants to enroll in other capacity programs, such as the NYISO SCR program
  - Focus on network peak reductions with separate day and night call windows
  - Target top 1.5% of Zone J peak to reduce the number of times the program is called during a program year
  - Change Day Ahead notification to avoid confusion
  - Implement the program for the full summer capability period
  - Change base performance factor to be based on average hourly kW performance
  - Expand program assessment period to 2012

- For CSRP only, the following program changes were also proposed in the filing:
  - Change to program payments
  - Allow enrollment within “capability-year”. Recapture participant penalties under certain conditions for CSRP 2010 penalties incurred

- For CPRP only, the following program changes were requested:
- Allow year-round enrollment
- Align energy and bonus payments across reduction size
- Change the cost of metering for the smaller CPRP participants, increase the commercial metering threshold
- Open up the program to Demand Response Service Providers

The Company also proposed changes to RSAP and NRP to target the top 1.5% of Zone J peak, change the Day Ahead notification to avoid confusion, and expand the program assessment period.

The recommendations, as accepted by the Commission in their order, issued January 20, 2011, “Order Adopting Modifications to Demand Response Programs”, were subsequently implemented. We have begun to see strong enrollment activity in both the CPRP and CSRP programs as of the enrollment period commencing April 1, 2011.
**Recommendation Number:** 34
Establish a base level of network reliability for new networks. (Conclusion 24)
Team Lead(s): John Mucci/Robert Schimmenti

**Summary of Implementation Actions:**

This recommendation is complete.

Con Edison measures reliability of its network systems by a reliability parameter entitled Network Reliability Index (NRI), which estimates the frequency at which cascading of feeder failures could be encountered in a network. An NRI event is defined as a situation where four or more feeders supplying one portion of a network are out of service at the same time under specific temperature/loading conditions. While this situation would not typically result in customer outages, it does increase the likelihood depending on variables such as temperature, loading conditions, network topology, and component distribution. The NRI value is a relative index that allows engineers to design and allocate reliability program dollars to achieve optimum system improvement. Due to the component dependencies relative to complex network systems, cascading feeder failures could result in significant equipment overloads, widespread outages, and lengthy restorations times for a given geographic boundary. A typical underground network supplies approximately 50,000 to 75,000 customers. For Consolidated Edison’s network systems the NRI reliability metric has been developed to reflect critical system conditions unique to the Company’s meshed network operation. In addition to this representative metric, an optimal target for network reliability is also needed against which progress, quantified by network NRI reduction, can be gauged. An optimal performance measure should not only drive current system reliability to higher levels but it should also allow for the inclusion of a performance buffer to guarantee that optimal system reliability is in fact satisfied. In addition, it allows for a consistent approach for capital program allocation by network.

When the reliability of the networks were initially evaluated using the earliest versions of the NRI simulation the results suggested that the NRI state described above might occur, on average, once-in-10 years across the entire network system. Distribution Engineering determined that this level of network performance was unacceptable due to the severity of associated regulatory, social, and financial impacts so they established an initial goal of a 100% increase in the years to an NRI state or, a once-in-20 years level. This specific reliability target resulted from informed engineering judgment and consideration of the practical constraints imposed by anticipated levels of network capital investment. Using that initial criteria to guide reliability efforts, the present likelihood of an NRI event somewhere on the system has improved to a current level of approximately once-in-23 years, satisfying Distribution Engineering’s initial reliability threshold.

The initial selection of a once-in-20 year period to an NRI state as the network reliability target has provided for a significant reduction in the level of NRI state occurrence and
satisfied the spirit of a conservative reliability design criteria that drives performance in a meaningful direction. It can be viewed as the first significant reliability threshold for meshed network performance. In any event, since the adoption of the once-in-20 year target in 1999, and its satisfaction by 2009, a great deal more has been learned about network behavior and performance and the Company is now in a position to better define network reliability thresholds.

Establishing a base level of network reliability allows Con Edison to identify the networks on which reliability funds should be targeted in order to provide an overall system improvement. Infrastructure investments are targeted to the lowest ranked networks in order to maximize the contribution of those improvements both within the network and to system-wide years to an NRI state. In order to provide for system improvement but keep costs down, Con Edison has identified a number of programs which will address network deficiencies and increase network reliability. The effectiveness of each program on a specific network is evaluated in order to determine the effects of reliability spending. The most cost-beneficial solution that meets the reliability goal is selected.

New networks are carved out of existing networks and therefore will consist of existing infrastructure that includes some relatively high failure-rate components. However, past experience with the establishment of new networks indicates that their individual performance far exceeds typical networks due to a marked reduction in the number of assets and increased margins on equipment and components.
**Recommendation Number:** 39  
Strongly link CECONY’s long-term electric plan with annual budgets, rate plans and 5-year capital plans. (Conclusion 4)  
Team Lead(s): Katherine Boden/Tim Cawley

**Summary of Implementation Actions:**

This recommendation is complete.

The Company developed a comprehensive Electric Long Range Plan (ELRP) document that will serve as a roadmap for the next 20 years. A copy of this document is available as the “Electric System Long Range Plan” attachment as completed for Recommendation 5. The ELRP provides a strategic framework for implementing plans to manage demand and supply, invest in infrastructure, provide environmental stewardship, and serve customers at a reasonable cost. The ELRP provides the necessary long term vision and context needed to support planning and budgeting for shorter term projects and programs.

Historically, and as observed by Liberty, the Company developed 10 and 20 year infrastructure plans for its electric transmission and distribution systems. These plans focused on ensuring that the systems had sufficient capacity to reliably meet customer energy requirements, and were based on stringent design criteria. The newly developed ELRP goes beyond that traditional approach by effectively integrating transmission and distribution system infrastructure plans with non-infrastructure related elements of our business, such as demand side solutions and renewable resources, into one comprehensive plan. In addition, the ELRP includes a supply outlook, because we are concerned about the total cost and the cost of supply is a major component of our customers’ bills.

Through this comprehensive planning process we gained a deeper understanding of the impact of various programs and initiatives on our customers’ bills. The long range plans were developed in such a way as to provide a clear line of sight between our initiatives and customer bills. We are focused on customer bill impact to strive to provide energy services at reasonable prices.

Costs to develop the ELRP totaled $2.2 million. Through this development process, we were able to establish a platform by which we can measure customer and business needs, risks, investments, and other key drivers across common assumptions and longer term timeframes. This shared platform increases transparency and gives direct line of sight to customers’ bills. We recognize that it is critically important to us optimize the management of component maintenance, repair, and replacement decisions to minimize cost impact to our customers. As a result of these optimization and efficiency efforts, we expect to experience $3.1 billion in cost avoidances and savings over the 20-year planning horizon, as compared with traditional approaches. In addition, the plan outlines potential opportunities.
for regulatory, tax and related reforms and utility ratemaking approaches that would be beneficial to customers.

Full details of the ELRP are discussed further in Recommendation 5.

By using this plan, we are now able to link our short term plans to our long term goals, to evaluate the impact to our customers when comparing different levels of investment, and to articulate the challenges we’ll have to overcome in the coming years and decades.

We are using the outcomes and goals of our long range planning efforts to improve our annual planning process. Key outputs from the long range planning process focusing on the corporation’s vision, mission, and strategic goals and objectives now serve as the primary drivers for each organization’s annual business planning process and the development of annual business plans.

For Con Edison’s electric, gas, and steam businesses, annual budgets and shorter term plans are linked to long term plans through development of annual business plans. These annual business plans have been standardized with uniform guidelines and templates. The guidelines specify a requirement that the annual business plan submissions provide a long term vision statement and long range strategy initiatives. Progress towards achieving these initiatives are assessed and measured in the annual business planning process.

Additional details of the Company’s improvements to its annual business planning process are discussed further in Recommendation 1.
**Recommendation Number:**  42

Prioritize CECONY capital projects and allocate funding using long-term economic analysis metrics as a significant decision factor. (Conclusion 8)

**Team Lead(s):**  Katherine Boden/Tim Cawley

**Summary of Implementation Actions:**

This recommendation is complete.

To address this recommendation, Con Edison has institutionalized the following two key prioritization practices as part of its overall improvement to its planning processes:

- **Prioritization metrics for electric operations investment:** The Company implemented process improvements to ensure that individual asset replacement and upgrade decisions are cost effective in comparison to other capital expenditure alternatives. Capital planning will be based on a repeatable, transparent process that provides specific direction regarding decisions made on asset replacement, deferral, and maintenance. A key metric in this process, the Network Reliability Index (NRI), is used for program evaluation and cost-benefit comparison.

- **Company-wide economic value analysis methods and metrics:** A Capital Optimization Methodology has been implemented. This methodology improves the alignment of capital project investments to their relative strategic value. The analysis utilizes cost-benefit curves which represent the incremental value gained for different investment portfolio options. The cost-benefit evaluations together with strategic objectives which cover longer term horizons are used for prioritization of investments and expenditures.

**Utilizing Improved Prioritization Metrics for Electric Operations Investment**

Electric Operations has adopted an improved prioritization process to ensure infrastructure investments and longer-term reliability projects are systematically addressed in capital investment plans. In early 2009, Con Edison’s Distribution Engineering department began a detailed analysis of various programs to ensure investment is prioritized to meet system performance objectives which comport with CECONY’s Electric Long Range Plan Development. This approach results in a quantified cost-benefit analysis to target investment to those programs yielding the greatest projected benefit. These cost-benefit relationships provide an effective means of gauging program effectiveness across investments and at varying levels of investment. Details of this analysis and its outcome are discussed further in Recommendation 24.

Cost-benefit curves as well as performance targets are used to determine optimal program investment levels. Calculated benefits of a program’s contribution to risk reduction and
achievement of strategic objectives are used to prioritize programs and to dictate program investment across programs. The primary metric for this analysis is Con Edison’s Network Reliability Index (NRI), which estimates the frequency at which cascading feeder failures could be encountered in a network. The NRI value is a relative index that allows engineers to design and allocate reliability program investments to achieve quantifiable system improvement as measured by the reduction of risk of a large scale network outage. In addition to this representative metric, a target for network reliability is needed to gauge progress, quantified by network NRI reduction. This target allows for a consistent approach for capital program allocation by network.

The Company’s Electric Long Range Plan utilizes NRI as one of the key metrics in long range planning. As part of the plan, a projects and programs model was developed to systematically evaluate the impact of specific programs and initiatives for a 20-year planning horizon and to measure the expected benefits of potential projects and programs on the basis of performance, cost, and risk, as follows:

- **Performance**: measures include contribution to transmission and distribution system reliability and environmental impact, including reduction in greenhouse gas (GHG) emissions as well as other environmental savings such as SF6 reductions throughout the system.
- **Cost**: measures include capital and Operations & Maintenance (O&M) expenditures and savings as well as the rate and bill impact of those investments.
- **Risk**: reduction is measured by the network reliability index (NRI) and by public and employee safety initiatives. These measures are consistent with the Company’s asset management practices and CECONY’s enterprise risk management (ERM) process.

The forecasted capital investments were each quantified in terms of their incremental impact on the performance, cost, and risk characteristics of the CECONY electric system. Outputs from this model were used to show the accrued benefits and associated costs in the Electric Long Range Plan. The Electric Long Range Plan is provided as the final deliverable for Recommendation 5.

Process improvements to prioritize electric operations reliability programs have allowed the Company to evaluate investment programs according to cost-benefit relationships, which are being used to compare and quantify the costs and benefits of electric operations programs. Although these cost-benefit relationships have not indicated the total termination of any one program, they have provided direction for the re-allocation of capital expenditure among the programs in order to optimize aggregate system improvement. Through April 2010, they allowed for the measured contraction of eight programs to the order of $40 million. This reduction represents a decrease in the scope of these programs and effectively removes these monies from the budgets for these programs. Reduction in expenditure and redistribution of available funds increases the impact per dollar invested thus providing more benefit per dollar to the customer.
Additionally, and as discussed in the Company’s Electric Long Range Plan, these relationships supply quantitative guidance regarding long-term program expectations and potential points of diminishing returns.

**Establishing Company-wide Economic Value Analysis Methods and Metrics**

Con Edison has additionally implemented a Capital Optimization Methodology to help evaluate projects enterprise wide, and make trade-offs across operating units through standardized analytical methods and guidelines. The goal of this process is to ensure that resources are efficiently used to reduce risks and meet long term strategic objectives. The Company will use this methodology to measure the portfolio’s cost, benefits and weighted strategic value, allowing for analysis of all projects as an integrated portfolio, with total cost, savings, and return on investment. This is an evolving process, and we will continue to improve our methodology for evaluating trade-offs of investment.

The goal of this methodology is to improve the alignment of capital project investments to the Corporate Strategy and other long-term goals and to bring together separate project selection processes under one comprehensive system and senior management led governance structure. It seeks to standardize the preparation of the project business cases, recommend an optimized project portfolio through constraint analysis, enable Project Portfolio reporting, and improve financial discipline for project investments. The process encourages project sponsors to submit projects that balance strategic and tactical focus, program benefits, and alignment with the Corporate Strategic Drivers.

Application of the Capital Optimization Methodology is expected to ensure visibility, transparency, insight and control for project portfolio management during the full project lifecycle from business case through project completion.

The capital cost to implement the Capital Optimization Methodology and accompanying prioritization model was approximately $1 million dollars, and ongoing costs of maintenance are expected to total $300,000 each year. The Company expects to receive savings that exceed this implementation and ongoing annual maintenance costs. The output from this methodology and prioritization model can be used to make more informed decisions in selecting the most strategic projects to work on during the Company’s budget cycles.

More detail around the Capital Optimization Methodology can be found in Recommendation 40.
Team 2 – Board Leadership
Executive Sponsor: Elizabeth Moore

Recommendations: 6, 7, 8, 43, and 56

Recommendation Number: 6
Revise Board committee structure to better coordinate functions and to focus on infrastructure planning, oversight and performance measurement.
Team Lead(s): Carole Sobin

Summary of Implementation Actions:

This recommendation is complete.

Management reviewed the structure and role of the Board committees, which included meeting with the Board members, and benchmarking the committee structure of the Company’s peers (as defined in our proxy statement). Based on the information gathered, the Board calendar and committee structure were revised, and dashboards were developed for each committee to focus on key operating and performance metrics, as appropriate.

Management met with the Board members to solicit input regarding (i) the role of the committees, (ii) the type and format of information to be provided by management to the committees, and (iii) approaches to providing the Board and committees with information. The information provided in the dashboards should assist the Board in its oversight of management’s infrastructure planning and performance management.

Management benchmarked the structure and role of the board and its committees against the Company’s peers. Based on information gathered from meetings with the Board members and benchmarking, management considered and recommended to the committee chairs and to the Board whether to combine, eliminate or restructure the committees, and whether to revise the Board and committee meeting schedule.

After such information gathering and discussion, the Board calendar was revised to allow the committees, as appropriate, to enhance their focus on infrastructure planning, operations oversight and performance measurement. Additionally, the charters of each of the committees were amended to provide that each of the committees will oversee the Company’s management of risks that have been identified by the Company’s enterprise risk management program relating to the duties and responsibilities of the respective committee.

The Management Audit report suggested that the Company consider combining the Operations Oversight and Environment Health and Safety (“EH&S”) committees. Management reviewed the committees’ roles with the members of the Board and it was
decided to maintain separate EH&S and Operations Oversight Committees to retain the respective EH&S and operational focus. However, a joint Operations and EH&S meeting was added to the Board calendar to provide an opportunity for both committees to review the Company’s operational plan before the annual budget review.

The roles and responsibilities of the Ad Hoc, Planning and Finance committees were also reviewed. The Board decided to discontinue the current Ad Hoc committee and reconstitute the committee on an as-needed basis. The Board also decided to add to the Finance committee the role of oversight of the Company’s business plan, including the Company’s business development proposals.

As part of our implementation of this recommendation, management liaisons were assigned to each committee to facilitate management’s role in assisting the Board with its oversight role. Furthermore, committee dashboards were developed to assist the committees, to focus on key operating and performance metrics, as appropriate. Each committee reviewed and approved their respective dashboard. The dashboards will also allow committees to receive information in a consistent format.

Implementation costs were minimal as this is a recalibration of functions related to the duties and responsibilities of the respective committees. The cost of performing the charter review and developing the dashboards was also minimal.

The benefit is expected to be enhanced Board engagement and oversight. The revised Board and committee structure, and the revised calendar will allow the committees, as appropriate, to enhance oversight of management’s infrastructure planning and performance management.
Recommendation Number:  7
Continue efforts to identify board candidates with energy utility experience (Conclusion 1)
Team Lead(s): Carole Sobin

Summary of Implementation Actions:

This recommendation is complete.

Liberty noted in the audit report that “Board members appreciate the need to assure that energy industry experience remains a focus of efforts to develop a list of candidates to fill future openings.” (Conclusion 2, page IV-21) The Company actively plans for such vacancies and has worked with an executive search firm in this process. Management recently discussed with the Corporate Governance & Nominating Committee and the Lead Director the Company’s efforts to identify board candidates with energy utility experience. In addition, management reviewed with the Board’s executive search firm the requirements for Board candidates, including the Board’s interest in identifying board candidates with energy utility experience. The search firm will maintain a list of candidates with such experience. Such expertise enhances the Board focus on issues that directly impact the Company.
Recommendation Number:  8
Incorporate changes in management’s form and schedule for infrastructure planning and budgeting into a more structure, resequenced, and more intensive regime of board review. (Conclusions 5 and 6)
Team Lead(s): Carole Sobin

Summary of Implementation Actions:

This recommendation is complete.

The Corporate Governance & Nominating Committee and Finance Committee chair of the Board of Directors have approved a revised 2010 board and committee calendar. The revised calendar incorporates changes in the committee structure and modifies the schedule to allow for a more structured review of short and long-range system needs in advance of annual budgeting, and provides for planning and budget review by the committees and the Board. In addition, the Board has received presentations on the development of the Electric Long Range Plan (ELRP).
Recommendation Number:  43
Require changes in capital projects and programs of more than 20 percent from the annual budget to be approved by the Board of Trustees (Conclusion 16 – Budgeting)
Team Lead(s):  Carole Sobin

Summary of Implementation Actions:

This recommendation is complete.

Management reviewed the Company’s capital budget process and evaluated the applicability of implementing Recommendation 43 in light of other Company processes that are being developed. For example, the cost management team is:

- establishing consistent, company-wide economic value analysis methods and metrics for capital projects and programs, and
- performing in-depth reconciliation on cost estimates with overrun to better understand the root causes of deviations.

Management also reviewed Recommendation 43 with the Chairs of the Finance Committee, the Operations Oversight Committee and the Corporate Governance and Nominating Committee, to solicit input regarding this recommendation.

The Board implemented this recommendation as modified. In response to Recommendation 6, committee dashboards were developed to assist the committees to focus on their oversight of management’s infrastructure planning and performance management. In response to this recommendation, the Finance Committee dashboard includes an indicator of "major projects within budget" to allow the Committee to review variations from budget for major projects. The Finance Committee will review the dashboard at each regularly scheduled Committee meeting. Furthermore, in November 2010, the Finance Committee and the Board determined to require Finance Committee pre-approval for projects with an estimated cost in excess of $50 million, and to require Board pre-approval for new projects with an estimated cost in excess of $100 million. During the January 2011 Board meeting, the Board amended the Board’s Delegation of Authorities to require such Board and Committee pre-approval.

Implementation costs to create Committee dashboards and amend the Delegation of Authorities were minimal. The benefit is expected to be enhanced Board and Finance Committee engagement and oversight. The Delegation amendment will provide enhanced Board and Finance Committee oversight over certain capital projects.
Recommendation Number: 56
Review the role of management, the Board, and/or its committees after serious events such as the 2008 electrical fatalities (Conclusion 6 – Work Management)
Team Lead(s): Carole Sobin

Summary of Implementation Actions:

This recommendation is complete.

Management met with the Corporate Governance & Nominating Committee of the Board of Directors to discuss the roles of management, the Board and its Committees after serious events. After such events, the Company reports the results of its investigations and lessons-learned to the Board and/or its Committees. The Company typically forms a cross-functional team of both management and union employees to identify the root cause of the incident. In that process, if it is found that an operating error occurred or if procedures were not followed, the Company takes corrective action. As an example of action taken by management in a prior incident, following a fatality in 2008, a thorough investigation was conducted and the results of the investigation were communicated to all Company employees and discussed at all-hands meetings. The Company reviewed processes that could prevent future incidents and established an Action Plan containing six recommendations with sixteen implementation items.

To enhance the Board’s role in the oversight of the Company’s management of risks, including the oversight of risks that could lead to serious events, the Company is expanding its use of Enterprise Risk Management (ERM) at the Board and Committee level. Enterprise risks have been assigned to Board committees to assist the Board in its risk oversight role. In addition, Management liaisons have been assigned to each Board Committee to facilitate management's role in assisting the Board in its review of serious events and risks.
**Team 3 – Rate and Financial Strategy**

**Executive Sponsors:** John McMahon and Robert Hoglund

**Recommendation Number:** 41

Work toward the re-establishment of multi-year electric rate cases. (Conclusion 3)

**Team Lead(s):** Stuart Nachmias, Chanoch Lubling

**Summary of Implementation Actions:**

This recommendation is complete.

By its March 26, 2010 Order Establishing Three-Year Electric Rate Plan, issued in Cases 09-E-0428 and 08-M-0152, the New York State Public Service Commission adopted a three-year electric rate plan for Con Edison’s electric service (for rate years beginning April 1, 2010 and ending March 31, 2013). The approved three-year rate plan establishes levelized rate increases of approximately $420 million each year. This plan is the culmination of an extensive effort by the Company and other parties to seek a multi-year electric rate agreement, which included settlement negotiations and a Joint Proposal (filed November 24, 2009) signed by 11 active parties, with no opposition.\(^1\)

The Company considers the adoption of the multi-year rate plan proposed in the Joint Proposal as a significant step toward a longer-term approach to utility ratemaking, an approach that allows the Company a greater opportunity to manage its business from a more appropriate multi-year perspective. The Company realizes that the development and adoption of the Joint Proposal should be seen as both an opportunity and a challenge to demonstrate customer benefits associated with longer-term ratemaking. The Company notes that multi-year agreements in principle have also been reached in the Company’s pending gas and steam rate cases.

Currently, the Company continues to develop its twenty-year electric system long range plan. The Electric Rate Case Team and internal budgeting teams have been involved and seek to provide linkage between the long range plan and annual budget, rate plan, and the 5-year capital plan preparation (see discussion at Recommendation No. 39). The long range plan is expected to recognize that opportunities exist to identify improvements in the

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\(^1\) In addition to the Company and Commission Staff, the signatories to the proposal included the City of New York, the Metropolitan Transportation Authority, Consumer Power Advocates, the New York Energy Consumers Council, the New York Power Authority, the Pace Energy and Climate Center, the Small Customer Marketer Coalition, the Retail Energy Supply Coalition and the E-Cubed Company on behalf of the Joint Supporters. These parties actively participated in the Joint Proposal’s development and filed statements of support. Other active parties who participated in the proceedings and who did not oppose the Joint Proposal include the County of Westchester, the New York State Consumer Protection Board, and the Utility Workers Union of America, AFL-CIO, Local 1-2.
regulatory framework that maximize the benefits of multi-year rate plans by creating appropriate incentive ratemaking mechanisms, fair to both customers and investors, that give stronger encouragement to utilities to identify and implement efficiency improvements and to take other steps that benefit customers over the long term. As part of the long-term plan implementation, the Company’s rate and financial team will seek to identify a ratemaking framework that addresses regulatory barriers, advances trust in the regulatory process by increasing transparency, creates better alignment of investor and customer interests, protects customers, provides financial integrity to the utility, fosters credibility, and creates an operating environment in which the utility will be encouraged to seek excellence in cost effectiveness and service.

The Company will work to improve future rate case presentations by linking needed new projects and programs to the long range plan vision and objectives to better justify such new programs and modifications. In addition, the Company will seek to improve the ratemaking format to address the financial barriers that were identified in the Liberty audit report and to increase opportunities for additional utility efficiency, setting incentives that drive toward lower costs while maintaining service adequacy.

Finally, in an effort to ensure that the Commission, Staff and all interested parties remain informed during the multi-year rate plan, the Company will continue to build effective relationships with all of its stakeholders.

In its March 26, 2010 Order, the Commission described the benefits of the three-year electric rate plan as follows:

We find that the three-year term for the Electric Plan offers significant benefits to ratepayers and the Company. For ratepayers, the benefits of knowing what their delivery rates will be over the next three years will make budgeting plans much more accurate and allow them to better arrange their activities. For the Company, the Electric Rate Plan will produce a more predictable revenue stream and the certainty to make investments necessary to continue the provision of safe and reliable service. Moreover, the Electric Rate Plan will allow the Company to direct resources that would otherwise be committed to annual electric rate cases to focus on operating the business and implementing the Liberty audit recommendations. [Pages 26-27]

On average, incremental non-staffing costs associated with electric rate case filings are between $1.2 and $1.6 million. The main components of these costs are for consultants and expert witnesses, public notice ads, travel expenses, and printing. Some of these costs (at least 20%) may be avoided in the longer term, to the extent that multi-year rate plans become the norm and the number of interim proceeding and collaboratives are not significant.
Team 4 – Work Management
Executive Sponsors: JoAnn Ryan and John Miksad

Recommendations: 32, 33, 44, 51, 67, 71, and 72

Recommendation Number: 32
Place all distribution tree trimming under a central corporate management function with accountability to corporate management. (Conclusion 22)
Team Lead(s): Matthew Glasser

Summary of Implementation Actions:

This recommendation is complete.

Centralizing all distribution line clearance under a single manager provides for consistent program oversight in all non-network regions; standardized work procedures and compliance with applicable specifications; a focus on staff development and professional accreditation; streamlined work unit descriptions and work specifications; and a consistent approach pertaining to the management of the contractor(s) in all regions.

The benefits of centralized program management and accountability and of uniform training and work practices have been reviewed and confirmed by our 2009 quality assurance program and have been demonstrated in improved quality of the work as compared to 2008. We expect continued work quality improvement. With the utilization of existing employee positions, this recommendation was implemented with no incremental cost.

The gross unit cost in 2009 was approximately $5,080/mile and for 2010 it is approximately $4,930/mile. The 2010 unit cost includes provisions for a notification forester in Westchester and back yard / climbing spans in Brooklyn and Queens that were additional out-of-scope unit costs paid in 2009.
Recommendation Number:  33
Strengthen the distribution vegetation management inspection program with accountability. (Conclusion 23)
Team Lead(s):  Matthew Glasser

Summary of Implementation Actions:

This recommendation is complete.

A Quality Assurance ("QA") program for all Electric Operations regions has been established to improve accountability in the line clearance function and ensure compliance with the current line clearance specification, Tree Trimming Requirements for Overhead Electric Distribution Lines. The QA group receives the schedule of all cleared feeder runs from the operating regions and selects which feeders to review and when. This process is separate from the Electric Operations region so as to maintain the integrity of such an independent evaluation. The results of recent reviews of both the Staten Island and Bronx/Westchester line clearance functions, as conducted by the QA group, have been made available to PSC Staff. In addition, the QA group audits the administration of the line clearance function.

The Company’s measures of success were developed post-audit, but provide aggressive goals for our tree trimming operations. QA field staff and line clearance personnel have been trained on the line clearance specifications and contract requirements through communication at morning meetings and pre-job briefings, and QA reviews of line clearance work will continue, so as to ensure specification compliance.

In addition, an Engineering Bulletin has been created to supplement the current line clearance specification. This bulletin provides guidance for the quality assurance field review and administrative audit requirements of the Line Clearance Program.
**Recommendation Number: 44**

Establish formal informational feedback loops for project analysis and project prioritization.

(Conclusion 17)

Team Lead(s): Robert Schimmenti

**Summary of Implementation Actions:**

This recommendation is complete.

The efforts under this recommendation have been coordinated with recommendations 24 and 72 because of their synergies. In addition, the feedback loops for project analysis and project prioritization will be finalized under recommendation 40 with the establishment of Enterprise Project Management Office and its associated tools.

As part of recommendation 40, the EPMO will standardize all processes associated with Project Management from project proposal, to selection, to management, to post-completion analysis. The post completion analysis will be expanded beyond the current practice of reviewing the cost-benefit analysis; it will involve a review of the actual cost versus the original estimate, lessons learned, projected savings versus actual, and level of spend versus benefit realized. By conducting this post-completion analysis, a feedback loop is initiated.

With the EPMO and its associated tools, feedback loops will be able to provide opportunities to evaluate and adjust projects and programs to ensure the appropriate balance of cost and value. Also, by annually reviewing the capital optimization portfolio, improved capital allocation decisions can be made which will achieve optimum value.

In order to increase the frequency of developing a cost-benefit analysis for projects that are justified based on cost savings, CI-291-1 “Cost-Benefit Analysis (CBA) Guidelines” was reviewed, revised, and issued in January 2010. The project cost level for requiring a Cost Benefit Analysis was lowered from $2M to $1M for all proposed capital and O&M projects, both specific and Information Technology (IT) related, that are based on cost savings. CBA training was administered in December 2009 to representatives throughout the Company.

Since this recommendation is directly tied to recommendations 24, 72 and 40, the cost-benefit for this recommendation is accounted for under these recommendations.
Recommendation Number:  51
Establish fleet size criteria based on historical data on total vehicle usage hours versus total physical work performed in hours in the region for each vehicle class. (Conclusion 6)
Team Lead(s):  Kenneth Jack / Tracy Cureton

Summary of Implementation Actions:

This recommendation is complete.

In response to the recommendation, a cross-functional team was developed consisting of Transportation and Electric Operations personnel. After reviewing available data, we decided to use fuel-consumption, human resource levels and work schedules as proxies for the number of physical work-hours supported by given assets. More wide-spread use of automatic vehicle-locating (AVL) solutions such as Avail and improved work-management systems are expected to supplement and/or replace these proxies providing more detailed insight into the day-to-day use of mobile assets.

The team was able to utilize existing systems and data to conduct this analysis. Transportation’s asset/work management system already had basic capabilities to monitor fuel consumption and crew assignments. This exercise required the team to proactively update and evaluate the available information.

A Microsoft SharePoint site was established to facilitate the collection of any data that was not available through the asset management system.

The team generated detailed vehicle inventory reports at the section and/or functional level as necessary to make comparisons among all Electric Operations groups in all regions. A scorecard to highlight comparative metrics such as “crews-per-vehicle” across regions for similar functional work was developed. For example, statistics on the use of equipment to support the Overhead Construction departments in multiple regions were grouped together on the scorecard to provide representative, side-by-side comparisons. Minimum fuel-consumption targets were set to indicate an appropriately utilized asset, with a built-in component to compensate for expected downtime of various assets. Vehicles not meeting the minimum target have been identified as candidates for elimination. In the absence of additional justification by Operations, these vehicles are phased out of the fleet, shared among organizations or redeployed in lieu of purchasing equipment for the annual replacement program. These reports are available through a Transportation computer system to allow for this analysis to take place on an on-going basis. The templates and approach for the asset review were then replicated for all parts of the Company with field operations. Seminars were conducted to orient field managers to the background of the audit and the basics of text-book fleet management principals, including performance standards, capital and maintenance costs and replacement strategies.
The approach identified assets that were receiving less than normal levels of usage, but the team decided to take the recommendation a step further to explore whether there were opportunities to redefine “normal” usage levels. All Operating Areas were surveyed regarding management practices in each area. This yielded additional insights into asset assignments, and the appropriate usage levels given their needs and constraints and whether other barriers existed to more effectively use mobile equipment.

The implementation of this recommendation included considerations for the sustained application of any new criteria. A detailed 12-page policy was developed that captures the efforts of the team, and describes the roles and responsibilities of both the Transportation department as well as the operating organizations to ensure appropriate utilization of equipment. The policy also details the various metrics to be considered, preparation of reports, evaluation of alternatives to traditional asset assignments and the on-going reviews of assets. Responsibility for the budgeting and planning of the fleet has traditionally been handled by Transportation, and revisions to applicable policies clarifies Transportation’s additional, centralized, responsibilities and authority for review and approval of asset plans. Lastly, it calls for detailed discussions of the business cases for changes in the size of the fleet. The policy has been incorporated by reference into the Corporate Instruction for the budgeting of General Equipment and is part of the annual budgeting process.

To date, over 100 vehicles were identified and removed from service or redeployed in lieu of purchases. It is expected that the fuel usage associated with these vehicles would likely be displaced to vehicles remaining in the fleet. Similarly, increased use of remaining assets would result in a minor increase to maintenance cost. However, in net terms, the reductions are expected to save approximately $200,000/year in avoided maintenance costs and reduce the capital investment (replacement value) of the fleet by $7.5M, or $750,000 on an annualized basis.
Recommendation Number:  67
Perform analysis on work items with unacceptable QA rejection rates to isolate performance problems. (Conclusion 5)
Team Lead(s):  Al Homyk

Summary of Implementation Actions:

This recommendation is complete.

The goal of the Central Quality Assurance (QA) group is to perform analysis on work items with high or unacceptable QA rejection rates to isolate performance problems and to communicate those findings to improve work quality.

2007 was the first full year when Electric Operations QA Inspections were performed by independent Central QA group personnel using standard audit protocols. In the past, these inspections were conducted by regional (non-independent) operating department personnel. They used techniques specific to the operating area and the pass/fail criteria was non-standardized, which meant that it could not be compared between operating regions. Quality Assurance began centralization in 2007 and this effort was completed in 2008.

QA established an Operating Procedure in 2008. The purpose of this procedure is to define the process by which Con Edison’s QA Program for the electric distribution system is to be systematically implemented. The Program’s primary purpose is to assure the health and safety of the public and our employees; provide for reliable and economical operation of the Company’s electric system; assure compliance with applicable codes and regulations; and focus Company resources in an effective manner.

Comparisons between QA results from 2007 and earlier years are not practical as “different yardsticks and different eyes” were used. Also, as mentioned on pg. XII-59 in the Liberty audit, Electric Operations created a five part QA KPI in 2006. The five parts were (1) Stray Voltage Testing QA, (2) UG Inspection QA, (3) Specification Compliance, (4) Operating Errors, and (5) Environment, Health and Safety (EH&S) Field Inspections. The QA KPI was reworked in 2008 and pertains to Stray Voltage Testing QA, UG Inspection QA, and Specification Compliance.

Table 1 below shows improvements have been demonstrated in 2007, 2008, and 2009 Electric Operations QA performance (the 2008 and 2009 rates includes both Inspection and Construction QA KPI data mentioned below). The table below reflects the QA passing rates and demonstrates that passing rates continue to improve since QA was centralized.

<table>
<thead>
<tr>
<th>Region</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brooklyn/Queens</td>
<td>66%</td>
<td>83%</td>
<td>93%</td>
</tr>
<tr>
<td>Manhattan</td>
<td>76%</td>
<td>77%</td>
<td>88%</td>
</tr>
<tr>
<td>Region</td>
<td>73%</td>
<td>79%</td>
<td>91%</td>
</tr>
<tr>
<td>-----------------</td>
<td>-----</td>
<td>-----</td>
<td>-----</td>
</tr>
<tr>
<td>Bronx/Westchester</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Staten Island</td>
<td>54%</td>
<td>86%</td>
<td>96%</td>
</tr>
<tr>
<td>Total</td>
<td>68%</td>
<td>81%</td>
<td>92%</td>
</tr>
</tbody>
</table>

**Table 1**

The Central QA group monitors and reports QA rejection rates on a monthly basis. Each month, the Central QA group sends emails to the Electric Operations General Managers in the various operating regions. This communication contains the month’s Key Performance Indicator (KPI) status for each operating region. The QA group points out deficient groups and lists the reasons why they failed inspections. Managers of the operating groups can monitor the failure trends month-by-month. In addition, these managers can either call up the Central QA group to get a rundown of failed inspections by section and worker or they can find these reports on the QA group’s web site.
Recommendation Number: 71
Implement a work management system in Electric Operations. (Conclusion 1, 4, 5, 16)
Team Lead(s): Peter Cooney

Scope / Plan:
Con Edison maintains a suite of applications that support the core work management processes within Electric Operations. These processes are defined around capital work (capacity, reliability, new business and public improvement), maintenance/inspection work and emergent work. New applications and enhancements to the existing systems have introduced new technologies, enhanced functionality and improved integration between the applications that comprise the work management suite. While these systems remain viable and technically supportable, the Company has been moving toward improvements to better facilitate the management of all aspects of work. Currently, users need to access and interact with a number of systems to support work initiation/bundling, planning, scheduling, dispatching, execution and completion of work. Enhancements in these areas would help users in Electric Operations with improved cost tracking, forecasting, work scheduling, status reporting and productivity analysis.

The scope and magnitude of Electric Operations’ capital construction projects and the complexities associated with its maintenance and inspection programs call for the review of business processes and the implementation of improved information systems to support the planning, execution and tracking of these comprehensive work programs. The improved systems should strive to provide the following functionality for Electric Operations personnel:

- A single repository for all planned and emergent work within Electric Operations so users no longer need to access multiple systems to process work
- An interface that provides detailed information about electric distribution assets that work is being performed against
- A comprehensive facility that helps manage all maintenance and inspection programs
- A mechanism to match project work requirements and tasks to worker skills and other resources such as vehicles and other equipment
- Trending and analysis of workforce and equipment performance
- A summary of all associated costs by work activity or project
- Interfaces to Finance, Supply Chain and HR systems that reduce clerical input and further streamlines processes
- A resource forecasting, scheduling and planning module
- Integration with mobile technologies allowing the transmission of data to/from the field

The audit’s recommendations regarding work management are in line with ongoing Company efforts to improve work management. Con Edison is currently engaged in a Phase 0 Assessment for Electric Work Management Business Processes and Information Systems.
This initiative will build on the project that the Company started in February 2009 and is currently in progress. A full time team comprised of key business users in Electric Operations, Information Resources support staff and consultants, are currently dedicated to this effort. The team plans to review all work management business processes, conduct the planning and analysis necessary to streamline the business processes as appropriate, and finalize a technology strategy for processing work within Electric Operations. This study would encompass all work processed by Electric Operations including:

- Emergency repairs and follow-up
- Maintenance and inspection of facilities
- New business construction and customer connections
- System performance/reliability programs

The assessment process will seek to involve:

- Stakeholder surveys
- As-Is process review
- To-Be review with best practices evaluation
- Development of software vendor business requirements for a RFP
- Development of software application scripts with demonstrations and review of vendor solutions
- Fit/Gap analysis and application selection for work management solution
- Detailed To-Be process development and application Fit/Gap analysis
- Development of final report including business plan, implementation plan, change management plan, technical architecture plan, RICEFW inventory (reports, interfaces, conversions, extensions, forms and workflow)

The Phase 0 Assessment Team will seek to identify opportunities to streamline processes and effect the changes necessary to establish a best practice work management program. The team will also determine whether Con Edison will continue to enhance the existing suite of work management applications or migrate to a new work management platform based on a leading commercial solution. The Phase 0 Assessment Team will also produce a detailed business case cost estimate, implementation plan and change management strategy for the chosen course of action.

The Company will also seek to evaluate the leading utility work management application solutions including those offered by IBM (Maximo), Logica, Ventyx and Oracle. Products of this type are used by many leading utilities worldwide and leverage the latest software, database and server technologies. They also include comprehensive asset management capabilities and help to facilitate the adoption of best practice work manage processes. Complex integration with customer service, mapping and outage management systems can also be accomplished through the use of products.

The new case management software project for Energy Services and the Safety Inspection Program/Joint Pole project will also be assessed as part of the Work Management System
Phase 0 Assessment to understand if these projects should be incorporated into a work management solution.

A detailed business case that justifies the Company’s course of action will be developed as part of the Work Management System Phase 0 Assessment effort.

**Detailed Phase 0 Assessment Deliverables**

The Phase 0 Assessment Team is tasked with compiling a comprehensive report summarizing the work management business process changes, technology strategy, and project cost estimate and implementation plan. The report is expected to be completed in December 2009. The report will include the following deliverables:

- Project charter statement
- Summary of streamlined business processes, developed by Electric Operations personnel, addressing all aspects of work management including a:
  - Summary of business processes and rules documented through use cases and decision trees
  - Summary of activities and/or business changes needed to achieve new business process
- Solutions summary and fit/gap analysis
- Summary of all required reports, interfaces, conversions and enhancements
- Summary of all benchmarking visits and project research
- Implementation project scope and exclusions
- Business case including ROI, summary of benefits and additional justifications
- Package selection decision or summary of enhancements to existing systems
- Request for Proposal (if required)
- Implementation team structure and summary of roles and responsibilities for all project resources
- Implementation schedule, including milestones and checkpoints
- Detailed cost estimate and cash flow summary for implementation
  - Software licenses and development
  - Computing infrastructure
  - Labor
  - Interfaces
  - Data Conversion
  - Testing
  - Training
  - Overheads and contingencies
- Testing strategy
- Change management plan addressing
  - Implementation impact on Electric Operations personnel and other stakeholders
  - Implementation impact on existing systems
<table>
<thead>
<tr>
<th>Major Activities and Milestones</th>
<th>Estimated Start Date</th>
<th>Estimated Completion Date</th>
<th>Actual Completion Date</th>
<th>Current Status</th>
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<tbody>
<tr>
<td>Document “As-is” high level process</td>
<td>5/09</td>
<td>5/09</td>
<td>5/09</td>
<td>Complete</td>
</tr>
<tr>
<td>Develop “To-Be” high level process</td>
<td>6/09</td>
<td>6/09</td>
<td>7/09</td>
<td>Complete</td>
</tr>
<tr>
<td>Evaluate software options and select solution</td>
<td>6/09</td>
<td>8/09</td>
<td>8/09</td>
<td>Complete</td>
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<tr>
<td>Detailed “To-Be” process design</td>
<td>8/09</td>
<td>11/09</td>
<td>11/09</td>
<td>Complete</td>
</tr>
<tr>
<td>Business Case and Implementation Plan</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Complete</td>
</tr>
<tr>
<td>Deliver final business case and Phase 0 Assessment report</td>
<td>9/09</td>
<td>12/09</td>
<td>12/09</td>
<td>Incorporated comments from Steering Committee to complete the Work Management System Phase 0 Assessment</td>
</tr>
<tr>
<td>Implement new process and organization changes, including standardization of forecasting, planning and scheduling functions</td>
<td>4/10</td>
<td>7/11</td>
<td>8/11</td>
<td>Complete</td>
</tr>
<tr>
<td>Design and configure base work management for Energy Services</td>
<td>2/10</td>
<td>4/11</td>
<td>4/11</td>
<td>Complete</td>
</tr>
<tr>
<td>Design, configure, and deploy Logica Asset &amp; Resource Management (ARM)</td>
<td>8/10</td>
<td>3/13</td>
<td></td>
<td>In Progress</td>
</tr>
</tbody>
</table>
Summary of Cost-Benefit and Risk Analysis:
The Work Management System Phase 0 Assessment Team is to compile a comprehensive report summarizing the work management business process changes, technology strategy, project cost estimate and implementation plan. The report is expected to be completed in December 2009.

Upon review of this comprehensive report by the Work Management Steering committee if the cost benefits are material as developed in the business case and implementation plan we would expect to begin the mobilization, design and deployment process in the first quarter of 2010.

Cost-Benefit:
The Phase 0 Assessment is expected to produce a business case that will define the costs and benefits associated with deploying work management applications or processes. The business case will define costs and benefits by year for O&M and Capital dollars. The costs and benefits would relate to the implementation plan that identifies the deployment schedule.

Risks:
1. Phase 0 assessment is dependent on the costs and benefits (savings) identified in the development of business case.
2. Alignment and coordination with other enterprise projects (PowerPlant, ERP)
3. Ability to facilitate process, skill and organization changes that may be required to implement the work management solution

Post Evaluation Process
There are a number of possible approaches that will be evaluated during the Work Management Phase 0 Assessment.
One possible approach would deploy new business processes as a replacement for some current key business processes, implement some organization changes, and deployment of some application technology to support process change. This phased approach and the duration could be in the range of 36 to 42 months.

Another possible approach is the deployment of an entirely new business processes, a new organization structure and new application technology as one major change initiative. This approach would move the organization towards “best in class” business processes, align the organization and give the business users applications and technology tools. The duration of this deployment could be in the range of 24 to 30 months.

Another possible approach would be to deploy new business processes and technology change with minimal organization change. This would give the business users the application technology to support new business processes but would not allow for alignment through organization change. The duration of this deployment could be in the range of 24 months.

Another possible approach would be to deploy new business processes and organization structural changes without new application technology. The duration of this deployment could be in the range of 12-18 months.

These various scenarios are some of the possible approaches that could be utilized to deploy new business processes for some current key business processes, provide a new technology through applications, as well as a new organization for selected business processes.

Each of these approaches as well as other variants is expected to have pros and cons around speed to realize benefits, ability to sustain benefits, long and short term efficiencies, risk to business during deployment, ability to learn and correct while getting feedback and many other factors.

The completion of the Work Management Phase 0 Assessment will seek to fully define the selected approach through a business case, implementation plans, change management plan, technology plan and risk assessment plan.

**Measures of Success:**
This initiative is in line with ongoing Company efforts. The measures of success would be defined at the conclusion of the Work Management Phase 0 Assessment project. These measures will be identified in the business case and implementation plan. The measures could include labor, labor overtime hours expended, contractor labor expended and other non-labor benefits as well as transaction transparency, cost visibility, enhanced customer satisfaction and cycle time benefits.
January 15, 2010 Update:

This recommendation is complete.

The Work Management System Phase 0 Assessment project began in February 2009 and concluded in December 2009. During this phase, the project team:

- Conducted workshops with numerous Subject Matter Experts (SMEs) from Electric Operations, Central Field Services, Central Operations and Corporate Accounting to understand “As-Is” processes and define detailed “To-Be” processes for work management.
- Conducted benchmarking visits and conference calls with 14 comparable utilities to understand how work is managed through process design, organization design and modern software applications. These companies included Dominion Resources, National Grid, Duke Energy, and Pepco (See the “Benchmarking” section of the Business Case report Appendix for a full summary of the benchmarking visits).
- Evaluated several software vendors in the work management space and selected a combination of Logica, Oracle, and Obvient as the proposed “To-Be” work management software suite providers.
- Assessed impacts to the Electric Operations organization and defined a comprehensive plan for Change Management.
- Defined the technical architecture needed to support the proposed applications and systems.
- Developed an implementation plan and estimated cost to deploy the new work management system applications and processes.

The Work Management System Phase 0 Assessment project focused heavily on developing the future work management processes for Electric Operations. The solution can also be expanded to other organizations in the Company such as Gas and Steam Operations and support organizations such as Central Field Services. The project team developed process designs for the main components of work initiation, design and estimation, prerequisite management, materials requirements planning, scheduling, work assignment, work execution, work closure, field reporting, contractor management, as well as forecasting and planning. These business processes were refined throughout the entire project and reflect the analysis and experience of the project team, Company-wide Subject Matter Experts (SMEs) for each process area, and best practices as implemented by other utilities. The project team used the proposed “To-Be” work management processes to define the requirements for a work management system application that would support these processes. The project team gathered over 660 business requirements to aid in the selection of the work management software package best suited to support the Company’s “To-Be” business processes.
The project team evaluated several options that included process and organizational changes. These changes were evaluated with and without enhancements to existing applications. The project team determined that process and organizational change coupled with a new technology solution was the best solution for the vision and goals of the project. The core software application selected is the Logica Asset & Resource Management (ARM) product suite solution. The Logica Asset & Resource Management product suite solution includes:

- **ARM Work Manager - Work Management Information System (WMIS)** – This module is a work management tool that supports the management of all types of work. The assignment of tasks to the appropriate resource uses business rules based on work type, geographic proximity, priority, or other user-defined business rules.

- **ARM Scheduler – Scheduler** is an automatic assignment and dispatch application designed to provide a single view of all resources and portfolios of work across the organization. The automated scheduling optimization module uses business rules and configurable scheduling constraints for efficiency. Work types or tasks can be automatically re-optimized as higher priority work types or tasks become available.

- **Real-Time Asset & Resource Management (RTARM) Mobile** – This mobile work management application enables information to be transmitted directly to and from field personnel. This application also supports timesheet generation and reporting capability.

- **ARM Asset Manager** – As a single asset repository, Asset Manager provides tracking of maintenance and inspection work tasks, asset history, and facilitates failure analysis.

The Logica Asset & Resource Management (ARM) product suite will be supported by the Obvient FocalPoint reporting tool for developing reporting metrics and by Oracle Primavera for longer range forecasting and planning. The Primavera product is part of the Oracle suite of products and will be used to perform long range forecasting (one to five years) and Planning (2 months to one year). Primavera is capable of projecting resource requirements (Labor, Material, and Equipment), and determining potential shortfalls. In addition, it provides a graphical view of the workload, assisting the user to level the workload by allowing the creation of different scenarios. The selected scenario can then be finalized and implemented based on budgetary approvals. In addition, Primavera will utilize data provided by Oracle’s Enterprise Resources Planning tools (ERP) to provide historical projections. Primavera will also be used to perform long term scheduling prior to design finalization. The Primavera toolset will provide an integrated solution so that project schedules can be developed showing dependencies and tasks and providing a visual representation in Gantt charts.

The deployment of the Logica Asset & Resource Management (ARM) product suite solution, Oracle Primavera and the Obvient FocalPoint reporting tool will support increased efficiency.
and effectiveness for field organizations in Electric Operations. It will also enhance visibility, process redesign and organization deployment and support improved cost management. The project team proposes deploying the new work management system and related processes through six core initiatives: Process and Organization for Forecasting/Planning/Scheduling, Work Management for Energy Services and full deployment in Electric Operations, Asset Repository, Mobile, and Contractor Management. The implementation is anticipated to take approximately four years. The first of these initiatives is expected to start late in the first quarter of 2010, and the last initiative would conclude in the first quarter of 2014. The total cost of this project is estimated to be between $138M and $174M. The capital costs range between $119M and $155M; O&M costs account for $19M. The total annual benefit which will be realized upon full implementation is between $45M - $48M.

Detailed Phase 0 Assessment Deliverables

The following deliverables were produced as part of the Work Management Phase 0 Assessment project:

- Project charter statement
- Summary of streamlined business processes, developed by Electric Operations personnel, addressing all aspects of work management including:
  - Summary of business processes and rules documented through use cases and decision trees
  - Summary of activities and/or business changes needed to implement new business processes
- Solutions summary and fit/gap analysis
- Summary of all required reports, interfaces, conversions and enhancements
- Summary of all benchmarking visits and project research
- Implementation project scope and exclusions
- Business case including payback period, internal rate of return, summary of benefits and additional justifications
- Package selection decision or summary of enhancements to existing systems
- Implementation team structure and summary of roles and responsibilities for all project resources
- Implementation schedule, including milestones
- Detailed cost estimate and cash flow summary for implementation, including:
  - Software licenses and development
  - Computing infrastructure
The Business and Information Resources (IR) technology team mobilized in February 2009. The first task involved preparing a Request for Proposal (RFP) for procuring a consultant experienced in work management system deployment, process design, and change management. Accenture, a leading consultant in the utility space, was selected based on their experience implementing work management systems at similar utilities, the quality of personnel that were to be assigned to the project, hours allocated to the project, reference review by the project team, and bid price.

The Accenture team mobilized for the Work Management System Phase 0 Assessment project in late April 2009 and initiated the Planning Phase of the project. The combined team conducted surveys and met with various stakeholders to develop the expectations for the project deliverables. The team reviewed the Accenture High Performance Utility Model (HPUM) (See the “High Performance Utility Model Diagrams” in the Business Case report Appendix for a picture of HPUM), a proprietary tool, which delineates processes in forecasting, planning, managing and executing work across four major work categories. The categories of work are capital system reinforcement/reliability, new business construction, maintenance & inspection and emergency.

- The processes included for forecasting and planning are: resource planning, contractor strategy, and delivery performance management.
- The processes included for managing work are: work initiation, design/estimate, prerequisite management, materials planning, scheduling, and assigning work.
- The processes included for work execution are: field logistics, work execution, contractor management, performance management, and work closure.
The project team held workshops with numerous business Subject Matter Experts (SME’s) in Electric Operations, Central Field Services, Central Operations, and Corporate Accounting and documented high level “As-Is” business process designs that mapped to the High Performance Utility Model (HPUM).

The project team assessed the Electric Operations current processes in relation to the utility industry leading edge practices. This was done using Accenture’s Capability Levels of Mastery model (CLM). The Capability Levels of Mastery provides a basis to describe the increasing aptitude of business functions within an operating model. Tangible characteristics are provided at four levels of maturity - from basic, to industry leading levels of capability. The levels help an organization establish both current and desired business capabilities with comparison to industry peers (See the “High Performance Utility Model Diagrams” section of the Business Case report Appendix for the CLM summary diagram). The high level “To-Be” workshops developed the business requirements documents and business scripts for the software selection process. A number of work management software vendors demonstrated their solution for the business scripts. After detailed analysis by the project team, the plan phase of the project ended with the selection of Logica’s Asset & Resource Management (ARM) product suite, Oracle’s Primavera product, and Obvient’s FocalPoint product.

The Analyze Phase of the project commenced with detailed “To-Be” workshops to develop the detailed business process designs. These detailed “To-Be” business process designs were used to validate the software solution and develop the required RICEFW (reports, interfaces, conversions, enhancements, forms and workflow) inventory. The project team developed the application, execution and operation architecture as well as a detailed technical estimate. The business case model, implementation plan and change management plan were also developed.

**Description of Phase 0 Assessment Methodology**

Electric Operations engaged in a Phase 0 Assessment for Electric Work Management Business Processes and Information Systems. This initiative started in February 2009. A full time team of key business users in Electric Operations, Information Resources support staff and experienced industry consultants were dedicated to this effort. The team reviewed current work management business processes, conducted the planning and analysis necessary to redesign the business processes as appropriate, and finalized a business process and technology strategy for managing work within Consolidated Edison Company of New York (CECONY) - Electric Operations. This study encompassed all work processed by Electric Operations including:

- System performance/reliability programs
- New business construction and customer connections
- Maintenance and inspection of facilities
• Emergency repairs and follow-up

At a high level, the Phase 0 Assessment Project involved:

• Stakeholder surveys
• High Level “As-Is” process review
• High Level “To-Be” process development with best practices evaluation
• Development of business requirements for software vendor review and selection
• Development of software application scripts with demonstrations by vendors and formalized review of vendor solutions
• Fit/Gap analysis and application selection for a work management solution
• Detailed “To-Be” process development and application Fit/Gap analysis
• Development of final report including business plan, implementation plan, change management plan, technical architecture plan, and RICEFW (reports, interfaces, conversions, enhancements, forms and workflow) inventory of requirements

The project team had the tasks of:

• Identifying opportunities to streamline processes and effect the changes necessary to establish a best practice work management program
• Determining whether Con Edison should continue to enhance the existing suite of legacy work management applications or migrate to a new work management platform based on a leading commercial solution
• Producing a detailed business case, cost estimate, implementation plan and change management strategy for the chosen course of action

The team evaluated leading utility work management application solutions including those offered by IBM (Maximo), Logica, Ventyx and Oracle. These products are currently used by leading utilities worldwide and leverage the latest software, database and server technologies. They also include comprehensive asset management capabilities and help to facilitate the adoption of best practice work management processes. Complex integration with customer service, mapping and outage management systems can also be accomplished through the use of these types of products.

The proposed Case Management software project for Energy Services and the Joint Pole project were also assessed as part of the Work Management System Phase 0 Assessment to understand if these projects should be incorporated into a comprehensive work management solution. The work management system will incorporate the functionality of the joint use agreement regarding the required notifications to Verizon. The work management system will interface with the software product that will retain the master pole ownership information (when constructed). After an assessment of the features and functionality of the Logica ARM Suite against the requirements of the Case Management project, it was determined (in collaboration with Energy Services) that not all of the critical
Case Management requirements were being met. Project management, workflow management, engineering support, mobile field enablement, scheduling, and the performance metrics components of the Case Management project were a good fit and therefore would be incorporated into the Work Management project. However, Energy Services requirements for customer interaction tracking, telephony integration, and document management are outside the scope of the work management project and will need to be filled by a case management commercial product, with the ability to interface with the work management project core solution. The Case Management project is a different effort from the work management project and will be led by Energy Services. This project will be seen as complementary to the work management project.

The Work Management System Phase 0 Assessment Team compiled a comprehensive business case with related documentation summarizing the work management business process changes, organization changes, technology strategy, project cost estimate and implementation plan. This business case defined the costs and benefits by year for O&M and Capital dollars. The costs and benefits relate to the implementation plan and the deployment schedule. This report and related documentation was completed in December 2009.

**May 15, 2010 Update:**
In late January 2010, the project team reviewed the vendor submissions to our Request For Proposal (RFP) for the system integration of the Work Management System. The project team performed technical evaluations, spoke with other utilities to discuss proposed vendor team members and held discussions with vendors to clarify their proposals.

In March 2010, Accenture LLP, was chosen as the system integrator for the project. Both the CECONY business and Information Resources leads met with the Accenture initiative leads to review and develop project schedules.

In addition, negotiations were concluded with Logica PLC for the Logica Asset and Resource Management (ARM) suite software, configuration services and system maintenance.

Starting in April, the CECONY team and Accenture team began the design phase of several initiatives, including:
- 1) Work Management for Energy Services;
- 2) Process design for Forecasting, Planning, Scheduling, Work Coordination and Supervisor Enablement; and
- 3) Integrated Design with Enterprise Resource Planning -Supply Chain team

The design phase of these initiatives will develop the requirements needed to build the processes, organization structure and application configurations for the build phase of these initiatives.
**September 15, 2010 Update:**
The work management project team has been progressing through the design phase of multiple initiatives as part of the overall project implementation. The Work Management for Energy Services initiative, which includes the replacement of the CORS (Commercial Operating Reporting System) legacy system with the Logica software, has completed design and is currently in the build phase. Testing will commence in October 2010. The Logica application suite will provide users with visibility to the current status of all work requests as the work request moves through initiation, service determination, design, scheduling, construction, close-out, and validation.

The integrated design phase is now complete and designs have been created in conjunction with the Company’s new utility-wide software system under development for our finance and supply chain functions, Project One.

Process design and role definition for forecasting, planning, scheduling, work coordination and supervisor enablement continues. This initiative will establish the organization, and new roles and responsibilities for carrying out the Company’s new work management processes and systems upon deployment.

In order to measure the readiness for, and acceptance of changes that will result from this project, an employee survey will be performed. This will be carried out jointly with the Project One team.

**January 15, 2011 Update:**
The work management project team has continued progressing through the design, build and test phases of multiple initiatives as part of the overall project implementation.

The Work Management for Energy Services initiative, which includes the replacement of the CORS (Commercial Operating Reporting System) legacy system with the Logica application, has completed the configuration build phase and functional testing. The Logica application is currently undergoing user acceptance testing by Energy Services subject matter experts. The initiative is on track for phased deployment beginning in the spring of 2011.

The work management project team completed configuration and is currently testing the Oracle Primavera software solution. This application will be used for the forecasting of work and resource capabilities.

In addition, the team has continued process design and developed training enhancements for the new positions of program/project planner, scheduler, and work organizer that are part of the newly created Work and Resource Management organization.
The team is also currently in the design phase of the new asset repository application. This application will contain information on electric distribution facilities and components, such as asset history and other asset parameters. Asset data will be utilized to initiate, bundle, design, and schedule work.

**May 15, 2011 Update:**

The work management project team has continued progressing through the design, build and test phases of multiple initiatives as part of the overall project implementation.

The team will complete the training for, and deployment of, the Logica Work Manager tool for Energy Services in May 2011. This initiative includes the replacement of the CORS (Commercial Operating Reporting System) legacy system and the implementation of Obvient FocalPoint for business intelligence dashboard reporting.

Detailed planning for the full deployment phase of the project has commenced. This initiative will include deployment of new processes and technology to support work management and scheduling for maintenance and inspection, capital construction, and emergency work. A key input to this will be the implementation of Logica’s Asset and Resource Management tool, and the migration of electric assets to one central repository to manage maintenance and inspection work on them.

In addition, staffing and implementation of the new positions of program/project planner, scheduler, and work organizer, as part of the newly created Work and Resource Management organization, are underway. This includes the deployment of specific process and organization structure changes (for scheduling, field supervision, and forecasting). The Oracle Primavera application has also been implemented for forecasting and longer range planning of work.

**September 15, 2011 Update:**

The work management project team completed two additional initiatives since the May 15, 2011 update and commenced the Full Deployment initiative of the project.

The Logica Work Manager tool was deployed for Energy Services to address the initiation of new business work in May 2011. This included the retirement of the CORS (Commercial Operating Reporting System) legacy system and the implementation of Obvient Focal Point for business intelligence dashboard reporting. The project team provided post-deployment support to the user groups throughout the summer months.

In addition, the Work and Resource Management organization was created and staffed with the new positions of program/project planner, scheduler, and work organizer. This new organization will forecast, plan and schedule construction work in electric operations, and
become the primary group that implements the new processes and technology in support of maintenance and inspection, capital construction, and emergency work.

In June, the project began the Full Deployment initiative. This phase of the project will deliver the Logica Asset and Resource Management suite across electric operations. Work will be initiated, engineering design and estimation for the electric distribution system will take place, pre-requisites for work will be managed, and work will be tracked and closed out in the Logica application. The Work and Resource Management organization will utilize Logica to see the entire breadth of work in electric operations and utilize the scheduling tool to assign work to field forces and track progress to completion. Electric distribution assets will be converted into one central repository to manage and schedule maintenance and inspection work on them, and the Obvient FocalPoint tool for business intelligence dashboard reporting will be further expanded beyond Energy Services to provide management reporting.

The project is currently on schedule and is expected to complete deployment of all process initiatives and new work management applications in 2014.

January 15, 2012 Update:

The work management project team continued work on the Full Deployment phase of the project. This phase addresses the entire work lifecycle for all types of electric distribution work, from work initiation, to design and estimation, scheduling (through the Logica ARM Scheduler tool), work execution, and closure.

The project team designed the configurations of the Logica ARM suite and will enter and test those configurations through April 2012. Test preparations have begun and include the identification of test scenarios and scripts. Training materials are currently being designed and built for the start of impacted user training in the summer of 2012.

The project remains on schedule for complete deployment of all process initiatives and new work management applications in 2014.

May 15, 2012 Update:

The work management project team continued work on the Full Deployment phase of the project. This phase addresses the entire work lifecycle for electric distribution work, from work initiation, to design and estimation, scheduling (through the Logica ARM Scheduler tool), work execution, and closure.

The project team has completed configuration of the Logica ARM suite. Test suites, cases, and test scripts have been created and both integration and functional testing has
Commenced. Training materials continue to be built for the start of user training in the summer of 2012.

A technology road show was delivered to change ambassadors and other company personnel to familiarize them with the process and application changes that will be implemented.

The project remains on schedule for complete deployment of all process initiatives and new work management applications in 2014.

**September 15, 2012 Update:**
The work management project team continues to work on the Full Deployment phase of the project. This phase addresses the entire work lifecycle for electric distribution work, from work initiation, to design and estimation, scheduling (through the Logica ARM Scheduler tool), work execution, and closure.

The project team has completed integration testing and the first functional test cycle of the Logica ARM Suite. The second test cycle is in progress and is planned for completion in the fall of 2012. This will be followed by one more test cycle and user acceptance testing, in preparation for deployment. Super user training has commenced and training for impacted users in Staten Island will begin in October.

The project remains on schedule for complete deployment of all process initiatives and new work management applications in 2014.
Recommendation Number:  72
Design and implement written project and program management procedures and expectations, including definitions of roles, responsibilities and expectations, cost control plans, and scope control procedures. (Conclusion 2, 7, 9, 13, 14, 15, 18)
Team Lead(s):  Alan Homyk

Summary of Implementation Actions:

This recommendation is complete.

The Company has developed a project management organizational structure, relevant training curriculum and requirements, and is in the process of staffing the department. An Electric Operations specification for Project Management was issued on 12/21/09; and the staffing expectations have been established. This specification and the new organizational chart have been made available to PSC Staff.

The specification provides a standard procedure for the development, planning, implementation, closeout and management of Electric Operations projects and programs. To ensure successful project and program management, Electric Operations has established a five phase Project Management process: Project Initiation, Project Scope and Funding, Engineering Design, Construction, and Project Closeout. This project management process provides the sequence of events/actions necessary to bring a project from initiation to completion. The specification defines projects and programs as work requiring engineering support which results in a modification to a system, structure or component that typically costs over $5 million and requires the support of multiple organizations to complete.

A Project Team consists of the Project Manager, Design Supervisor, Construction Manager, and associated financial and EHS support personnel. Project Managers are assigned to manage projects and programs. Project Managers may also be assigned to oversee work that costs less than $5 million if it is sensitive or warrants high level attention such as PILC (paper impregnated lead cased) cable replacements for some regions, OSMOSE C-Truss work, and overhead secondary reliability. Costs for projects less than $5 million will generally continue to be monitored and controlled by the Planners and their respective Managers and General Managers.

The Project Manager has overall functional responsibility and authority for the successful planning, execution, and closure of the project. The Project Manager has the authority to direct all personnel in matters associated with the project. The Design Supervisor manages the engineering design phases of a project. The Construction Manager builds the project and is responsible for all underground and overhead facilities and equipment installed or renovated by Company forces or Contractors working for the Company. The Construction Manager is responsible for ensuring an appropriate number of Field Planners are assigned to the Project. The specification on Project Management specifies in detail the
responsibilities and functions of the Project Manager, Design Supervisor and Construction Manager during each of the five phases of the project management process.

The following benefits are expected to be gained by formalizing the project management function:

- Improved ownership/accountability of projects at a manageable level
- Better coordination of hand-offs
- Improved management of regulatory requirements
- Improved coordination with stakeholders: organizations, regulators, communities
- Better long-term planning
  - Schedules
  - Budgets
- Improved knowledge transfer
- Standardization of processes across the Company
- Improved focus on financials/schedule

The greatest benefit would be for better cost control and schedule accountability.

Although delays and/or project budget variances are sometimes unpredictable, we estimate that Electric Operations Projects will be completed 1% more efficiently through the implementation of a more structured and formalized approach to project management.

The 2010 capital budget for Electric Operations is $818 million. A 1% efficiency improvement on this total spending level is $8.1 million.

The costs for implementing the program are associated with staffing, software, certification and training. Approximately 8 individuals will be assigned as full-time project managers throughout Electric Operations. The fully loaded cost of these individuals is listed below:

- 8 people X $150,000 per year (salary plus benefits) = $1.2 million annual salary costs.

- Project management software will be required at a cost of $50,000 per year.

- Each individual will also require training so that they may become qualified as a Project Management Professional (PMP Certified); and then maintain their certifications (initial and annual cost to maintain certification estimated to be $5,000).

The total estimated cost to implement this program is calculated below:
• $1.2 million (salaries) plus $50,000 (software) plus $5,000 (training for PMP certification) = $1.3 million
Team 5 – Cost Management
Executive Sponsors: John McAvoy and Claude Trahan

Recommendations: 9, 10, 40, 45, 46, 47, 48, 49, 50, 52, 62, 65, 68, 69, 70, and 73

Recommendation Number: 9
Increase emphasis on efficiency and effectiveness in operations auditing. (Conclusion 10)
Team Lead(s): Louis Bevilacqua / Nicholas Colonna / Joseph P. Liotta

Summary of Implementation Actions:

This recommendation is complete.

Auditing has completed several measures to address this recommendation. In 2009, a new section was established in Auditing to focus on construction projects, contractor activity and Energy Services.

The section will conduct comprehensive project assessments that will analyze key aspects of the contractor procurement, administration and oversight processes. The assessments will include, but not be limited to, detailed reviews of contract scope documentation, cost estimates, bid packages and payments to contractors.

Project cost estimates and cost estimate increases will be reviewed to assess the quality of the estimates and their alignment to the project scope. Payment analyses will assess if payments are processed according to the contract terms and conditions and authorized, by the correct authority, for work that has been completed. The payment reviews will also assess if payments have been made for out of scope deliverables and if significant time and material costs have been incurred.

A new Section Manager has been hired to lead the group, and two auditors with construction audit experience have been hired. One auditor has been reassigned from the Operations Audit section. One additional auditor will be hired in early 2010.

A comprehensive annual Audit Plan for 2010, covering Construction and Energy Services projects at CECONY and Orange and Rockland, has been formulated. The Audit Plan dedicates an increased amount of audit hours to operational efficiency, contractor oversight, and enforcement and compliance with environmental, health and safety procedures. The Audit Plan will also assess the adequacy of other major contracts in place in the Engineering and Information Technology areas of the Company. The Audit Plan incorporates analysis techniques and other recommendations from KPMG’s investigation into the 2009 Construction arrests. In addition, the 2010 Audit Plan identifies the relationship of each audit in achieving the three objectives of internal control as specified in
the publication *Internal Control - Integrated Framework* of the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. The three COSO objectives are the effectiveness and efficiency of operations, the reliability of financial reporting and compliance with applicable laws and regulations.

In addition, Auditing purchased software to automate the analysis of data to assist in the auditing of these functions. The software, ACL Audit Exchange, is widely used by audit departments to analyze data sources and identify anomalies and potential instances of fraud. Auditing, Construction and other organizations in the Company are expected to utilize the tool.

Approximately $550,000 will be expended annually to maintain the new Auditing section. An additional $150,000 (one time cost) has been expended to purchase the ACL analytical tool.

These measures will facilitate improved monitoring of Construction and Energy Services projects and major contracts. In addition, they will help enforce adherence to contract terms and conditions and mitigate potential cost overruns associated with deviations from contract provisions. The measures are also expected to help to deter and prevent recurrence of fraudulent activities in these areas.

In addition to identifying inappropriate overcharges, the new group will work with Construction and other Corporate organizations to identify process improvements and controls and standardize policies and procedures to further reduce potential inappropriate charges and payments to contractors.
Recommendation Number:  10
Make consideration of Enterprise Risk Management a more structured part of audit planning. (Conclusion 11)
Team Lead(s):  Louis Bevilacqua / Nicholas Colonna / Joseph P. Liotta

Summary of Implementation Actions:
This recommendation is complete.

Auditing has integrated the risks identified as part of the Enterprise Risk Management (ERM) Program into its annual Audit Plan. Both Directors in Auditing continue to participate on both the Administrative Risk and Operating Risk Committees and provide substantial input in the risk identification, assessment and evaluation process. As part of the development of the 2010 Audit Plan, Auditing adopted a more structured approach and cross-referenced each planned audit to an identified administrative or operating risk. This allows Auditing to have a more structured process to ensure coverage of the key risks in the 2010 Audit Plan.

The 2010 Audit Plan is a comprehensive program of internal audits to ensure an independent assessment of the adequacy and effectiveness of the internal controls that govern the operations of Consolidated Edison, Inc. (CEI) and its subsidiaries. This was accomplished by aligning Auditing’s strategies and priorities with the primary risks identified in the CEI ERM Program, as well as incorporating lessons learned from events that occurred in 2009, including the arrests of Construction personnel, and significant environmental and safety incidents.

Additionally, we obtained the input of senior management on potential audit assignments. The 2010 Audit Plan includes a number of first time audits, pre-implementation testing of new systems that are being installed, and recurring controls testing that is required under Section 404 of the Sarbanes-Oxley Act (SOX) of 2002.

A comprehensive financial reporting risk assessment was also performed during the preparation of the 2010 Audit Plan. This risk assessment is an integral part of the planning process and helps to determine key audits for the Plan. These audits include assessments of potential fraudulent financial reporting, misappropriation of assets, and unauthorized or improper expenditures, all key enterprise risks.

Based on a financial reporting risk assessment, we adopted a more effective SOX control testing schedule that provides for a more balanced Audit Plan and enables the scheduling of more traditional in-depth audits. The revised SOX testing schedule calls for a new rotational testing program, over a seven-year period, of the controls that are not required to be tested annually. This new rotation provides assurance that all SOX controls are tested over a seven-year period. Using this approach, in 2010 we will test additional SOX controls in the
areas of financial reporting, energy management, fixed assets, material and supplies, payroll, purchasing and payables, revenues, and information technology.

The 2010 Audit Plan also incorporates activities to address the recommendations proposed through an additional third-party quality assessment review. These activities will improve the effectiveness of Auditing, broaden the scope of the Audit Plan and improve alignment with ERM activities. These activities include:

- Creating a new Director position in Auditing responsible for Investigations, Ethics Compliance and Training, the Ethics Helpline, EH&S audits, FERC Compliance, and Corporate Policies and Procedures. The position better aligns activities and helps the other areas focus on core audit activities.

- Creating a new section in Auditing to focus on construction projects, all contractor activities and Energy Services to help mitigate the risks associated with fraudulent activities in these areas, such as those exposed by the arrests of Construction personnel in 2009.

- Expanding audit coverage by incorporating an increased number of integrated audits and leveraging, where appropriate, the work conducted by operational quality control groups. In addition, the 2010 Audit Plan incorporates a new seven-year rotational testing schedule for the SOX 404 audit plan for non-key controls allowing Auditing resources to focus on additional risk areas.

The audits contained in the 2010 Audit Plan were mainly identified by the ERM Program and our financial reporting risk assessment. This approach allows for a structured methodology for setting priorities and directs resources to the most critical areas. Through this effort we identified a number of risk-related topics for the 2010 Audit Plan including, for example, a review of controls over the accounting for collateral on energy transactions, accounting for emissions allowances, electricity and gas procurement, and a review of critical computer systems used to manage electric outages.

Public and employee safety remains a prime concern. Therefore, in 2010 we will be increasing the amount of unannounced inspections focusing on Company and contractor crews performing street work, and reviewing the adequacy of job briefings and work area protection at job sites. Additional unannounced audits and inspections assessing compliance with other key EH&S risks will be conducted. Furthermore, audits to assess the status of recommendations from critical incidents, which occurred in 2009, are scheduled.

Electric, gas and steam operations will be reviewed to assess operational efficiency, cost management and compliance with environmental, health, and safety issues. Selected audits including storm preparation and response, NERC reliability assessments, and reviews of work management and inspection practices will be conducted. We will also conduct a
comprehensive assessment of water pollution controls at substations and generating stations.

There were no incremental costs expended to improve alignment between the annual Audit Plan and ERM Program. However, certain benefits, including proactive risk assessment and evaluation and reduction of risk exposure, are expected to be realized.
**Recommendation Number:** 40
Establish consistent, company-wide economic value analysis methods and metrics for capital projects and programs. (Conclusions 6 and 7)
Team Lead(s): Nicholas Colonna / Frank LaRocca

**Summary of Implementation Actions:**

This recommendation is complete.

In response to this recommendation, the team developed and implemented a new process that standardizes the selection of capital projects using measures to achieve the highest strategic and financial value for our capital investments. It sought to achieve the following goals:

- **Standardize all Project Management processes from project proposal, to selection, to management, to post implementation analysis**
  - Build upon newly standardized processes to implement a company-wide prioritization methodology
  - Perform this for all operating groups in CECONY through a staged implementation

- **Develop supporting material and design and implement a governance structure and processes to:**
  - Standardize the preparation of the project business cases
  - Recommend an optimized project portfolio through constraint analysis
  - Improve financial discipline for project investments
  - Demonstrate the economic value of individual and categories of project and portfolio investments

**Summary of Actions**
Con Edison has developed a Strategic Alignment Methodology (or Methodology) to help evaluate projects enterprise wide, and make trade-offs across operating units through standardized analytical methods and guidelines. The goal of this process is to ensure that resources are efficiently used to reduce risks and meet strategic objectives. The Company will use this methodology to measure the portfolio’s cost, benefits and weighted strategic value, allowing for analysis of all projects as an integrated portfolio, with total cost, savings, and return on investment. This process is an evolving process and skill set that we will continue to develop to standardize our methodology for evaluating trade-offs of investment.

This Methodology is being managed by Con Edison’s Enterprise Program Management Office (EPMO), has been tested, and is in production company-wide. This Methodology provides a systematic, repeatable and quantifiable process for evaluating and ranking the
financial and strategic value associated with each proposed program or project by organization and across the Company. It adds structure and analysis to the investment decision.

**The Strategic Alignment Methodology**

The goal of this methodology is to improve the alignment of capital project investments to the Corporate Strategy and other long-term goals. It seeks to standardize the preparation of the project business cases (also known as project justifications or white papers), recommend an optimized project portfolio through constraint analysis, enable Project Portfolio reporting and improve financial discipline for project investments, and to bring together disparate project selection processes under one comprehensive system and senior management led governance structure. Policies and procedures will be implemented to have all projects submitted, rated and selected based on the project’s merit which includes the cost/benefit analysis and strategic objectives. A goal of this process is to encourage project sponsors to submit projects that balance strategic and tactical focus, return on investment, and demonstrate close alignment with the Corporate Strategic Drivers.

Application of the Strategic Alignment Methodology is expected to ensure visibility, transparency, insight and control for project portfolio management for the full project lifecycle from business case through project completion. This effort is being supported by:

- Standardization of capital project proposals
- Implementation of a portfolio analysis software package
- Adoption of an associated governing structure and related processes.

**Standardization of Capital Project Proposals**

As a prerequisite for implementation of the Methodology, the team standardized the capital project proposal process. The team took the first step by standardizing project proposal and justification documents through the establishment of a common template. This new project justification template includes fields to enable and facilitate economic analysis for all of capital expenditure projects and annual capital programs by Business Area or for the entire Corporate Capital Portfolio.

**Implementation of a Portfolio Analysis Software Package**

To fully take advantage of this information, the team identified, installed and configured a portfolio management package. This software includes a prioritization model to perform mathematical analysis and also serves as the consolidated library for all proposed capital projects. It was configured to match users’ needs, users were trained for its use, and a User Guide was developed.
Analysis at the Portfolio Level
The prioritization model and its inputs are the basis of the Methodology. Inputs are derived from project justification documentation and an evaluation of each project’s ability to perform to “Impact Statements.” Impact Statements are meant to assess the level of a project’s impact on a strategic driver, provide a clear and consistent measure for each project, and achieve objectivity in the process. For example, the business driver “Reduce Costs,” is described as “Reduce costs through efficiency programs, standardization of processes, synergies across businesses, etc.,” and projects and programs are rated for this driver according to their expected ability to achieve quantifiable cost savings over different periods of time. In this way the methodology applies consistent economic value metrics, and weighs quantifiable outcomes against strategic drivers. After these inputs are established, different portfolios of investment can be analyzed according to their ability to impact each driver or a combination of drivers. “What-if” analyses can be performed in this framework to evaluate the impact of constraints, so as to assess portfolio characteristics under different scenarios for spending levels or changing priorities (such as to consider new regulatory mandates).

The analytical output from the prioritization model is never viewed as the final or complete results that dictate the project portfolio selection. A prioritization team consisting of subject matter experts utilizes the prioritization model output in a series of exercises where it is reviewed by various project attributes, mixed with historical data and business knowledge, analyzed and weighed. The final project portfolio is based on evaluation of results from the prioritization model together with business judgment.

Analysis at the Project Level
By combining the data from standardized project justification documentation with the capabilities of the prioritization model, users can perform cost benefit analysis, net present value (NPV) calculations and evaluate ongoing costs. These metrics serve as the basis for longer-term economic analysis. Such analysis and metrics demonstrate and compare the economic value of various projects or programs for their Strategic Value and financial impact. These metrics allow projects and programs to be compared to each other, and those with the highest Strategic Value and Financial impact are looked upon most favorably. Multiple economic analyses are performed such as the Efficient Frontier model which determines the value of incremental spend related to additional Strategic Value gained.

Benefits of the Strategic Alignment Methodology
The Methodology ensures consistency, visibility, transparency, insight and control for the selection of projects and continued oversight of project portfolios. Policies and procedures ensure that all projects are submitted, rated and selected based on the project’s merit and alignment with the corporate strategic values. The process ensures financial investments are made in the most strategic manner prioritizing the right work for the right timeframe.
The Methodology provides each operating area with quality data and analyses that enable them to more effectively manage their business processes and make more informed business decisions.

**Governance of the Strategic Alignment Methodology**

A governance structure has been developed to support this methodology in each operating area. This includes establishing a prioritization team consisting of subject matter experts who review and rate projects against the strategic drivers by means of the Impact Statements. A pilot was performed in 2009 to establish the governance structure in each area, and to familiarize the Operating Areas with the methodology and prioritization model.

Two Company-officer groups currently provide the governance structure for implementing and maintaining the Methodology. The Company’s Senior Officers function as the “Stewards of the Corporate Strategy.” They define, prioritize and communicate the corporate strategic objectives, and they ensure a disciplined focus on process improvement, return on investment and cost containment. The Vice Presidents from each operating area function as the “Business Unit Strategists” and through a combination of the software prioritization model’s recommendations and business knowledge, a portfolio of projects is identified for each area which is sent to the Senior Officers for final approval.

As highlighted above, basic steps in the Methodology are:

1. **Perform Strategic Value Analysis to establish the comparative costs and benefits of each project**
   - Strategic Driver definition: Con Edison’s Corporate Strategic Drivers are used as the basis for evaluating the value of each project.
   - Strategic Driver Prioritization: Strategic drivers are ranked through a pairwise comparison by the Senior Officers to determine the ranking and weighted value of each strategic driver in comparison to another strategic driver.
   - Impact Statement Definition is developed for each strategic driver and they provide a clear and consistent measure for each project. These impact statements provide comparative measures from “Extreme” to “None” as an evaluation of the extent to which the project will contribute to achievement of the Company’s strategic objectives.
   - Project Assessment: Each project is assessed against each strategic driver and a value is assigned.
   - Project Prioritization: Each project’s strategic value is calculated.

2. **Perform Portfolio Analysis and Constraint Analysis**
   - Multiple economic analyses are performed such as the Efficient Frontier model which determines the value of incremental expenditure related to additional Strategic Value gained.
b. “What if” scenarios are conducted to identify the impact of cases where less or more funding opportunities affects long term financial commitments for multi-year projects

3. Project Portfolio recommendations are made, reflecting economic analysis performed

4. Final Project Portfolio recommendations are reviewed with Senior Officers and the approved programs and projects are added to the Board Budget

Configuration of the prioritization model required input from all organizations. A committee was established to identify the business needs and to develop and incorporate supporting inputs such as the Enterprise Risk Model, white paper fields, and the ability to run reports. A training program and user guide were developed. The training was completed over a two month period. The classes were small (no more than 7 people), and consisted of 4 hours of “hands on” training. During the sessions, we would accept suggestions and requests for further configuration of the prioritization model to ensure we captured the needs of the organizations.

There are several benefits of using the Methodology. First, the output from the prioritization model can be used to make more informed decisions in selecting the most strategic projects to work on during the next budget cycle. Secondly, the prioritization model can be the repository for all project ideas and submissions. It can also be used to decide the next project to undertake if funds become available, and the next project to curtail if necessary.

This Methodology is helping organizations make better, well-informed decisions about project selection and expenditures. The governance process is ensuring that all levels of management in the organization have an understanding and voice in what projects are selected and the value of each.

**Enterprise Program Management Office (EPMO)**

In addition to building the Methodology, Con Edison has established an EPMO to promote the following initiatives in support of effective project management:

- Standardize Project Management Best Practices
- Increase Project Manager Competency
- Implement Portfolio Management
- Implement Project Management execution software

This EPMO is being developed to foster disciplined project management and disseminate internal and external project and program best practices across Con Edison. Expected benefits of the EMPO include: increased value and strategic alignment of investments;
transparency in selection and execution of project portfolios; reduced project execution risk; availability of coaching, mentorship and training to our project managers; and development of supporting processes and technologies.

The EPMO will be responsible for creating and providing governance for the Enterprise Project Management framework and infrastructure. The framework is designed to establish the roles, responsibilities and accountability for capital project execution. The EPMO will coordinate with multiple Con Edison organizations, such as Talent Management, Cost Management and other business unit project management components to build the framework and infrastructure including a project management knowledge repository of best practice processes and templates to ensure consistency across Con Edison capital projects and programs.

The EPMO is expected to advance the adoption of best practices in project management, from inception to execution, monitoring, delivery, and closeout to include a post completion benefits analysis. The EPMO will create a collaborative environment for Project Managers to work together and increase their skills. It is meant to facilitate the growth of project management professionals and will focus on the soft-skills, including listening to sponsors, feeling out problems, managing customer expectations and the facilitation of project teams in a matrixed environment, as well as skills in estimating, scheduling, and scope management.

Additionally, Con Edison project managers and employees interested in project management have formed a Project Management Society to support these project management initiatives with the following deliverables:

1. Competency Development – Project Management as a career path
2. Knowledge Repository – environment to support standardized project management processes, templates, guides and examples
3. Standardization and Improvement of Project Management Processes – a continuous improvement processes which seeks to identify internal and external Best Practices process and templates
4. Society Knowledge Exchange Activities – Society-sponsored programs and activities that are designed as educational activities or information sharing activities among members of the Society

The standardization of project management processes, integration of tools, and increased project management competency will lead to improved project management performance and capital utilization.

We expect to accrue benefits from implementation of a company-wide prioritization methodology based on consistent economic and other quantifiable variables. This new process will increase our effectiveness in directing capital investment to those projects with the greatest strategic value, and therefore resulting in benefits to customers. The addition
of an accompanying governance structure and EMPO will increase accountability, project management expertise, and add standardization to project execution to increase our capital utilization rate.

Through these new resources and processes, we fully expect to realize savings to minimally exceed the total cost of $1 million for implementation as well as the ongoing annual cost to maintain of $300,000.
Recommendation Number:  45
Implement a holistic approach to cost management that is designed and built around three key elements: (a) a guiding philosophy; (b) a formal, structured cost management plan; and (c) building blocks of comprehensive supporting capabilities (Conclusions 1, 3, 6)
Team Lead(s):  Nicholas Colonna /Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

We are dedicated to continued implementation of enhanced cost management strategies to foster smarter business practices. Internalizing this approach to cost management has given rise to modifications in our attitudes and behaviors as we have adopted a new philosophy for cost management and strengthened relationships between line and financial groups. We have outlined our commitment to achieving this excellence in the following guiding principles and strategies:

- Plan for cost management
- Set goals and expectations
- Be accountable
- Maximize productivity
- Actively manage costs
- Communicate and build relationships
- Share Lessons Learned
- Continuously improve

Evaluation of cost management skills, roles, and responsibilities has led to the development of new training courses, a career development path for cost management, and development of training programs and content for cost management and line personnel. These changes have been reinforced through extensive presentations, a Postmaster announcement to all Con Edison employees, and other methods to communicate the importance of cost management and adoption of enhanced practices.

This enhanced “holistic” approach to cost management will yield many benefits. Costs and benefits associated with specific activities, for instance creation of an Auditing Operations section, training and course development, analysis of overtime expenditures, development of a Lessons Learned infrastructure, and increase project management integration, are addressed individually within each associated cost management recommendation (see recommendations 9, 10, 40, 46, 47, 48, 49, 50, 52, 62, 65, 68, 69, 70 and 73). Several costs and benefits are global in nature. Most notably, the following were required to set the groundwork for enhanced cost management:

- Extensive team time spent over the span of one year to coordinate and implement the work plan; this effort included the direct involvement of five executives and
more than 15 other employees, and contributions from numerous others. The originally estimated cost for this work was $1,000,000. The actual cost to implement these recommendations was about $500,000. This reduced cost resulted from the implementation all cost management focused recommendations as a single team effort, thus removing duplicative tasks (e.g. process definition, creation of background materials, studies and analysis, and communication).

- Third party assessment (consultant’s report) cost $150,000. This represents a reduction of $50,000 from the original $200,000 estimate. To reduce costs paid externally, the team limited the scope of the consultant’s evaluation and focused on benchmarking

Benefits achieved will exceed the above described costs and reflect:

- **Alignment**: The team advanced cost management momentum at all levels of the Company. Organizational modifications were made to balance consistency, priority of cost, consistency of policies and procedures, employee development, partnering between financial and operational groups, and the coordination of global and local goals.

- **Business process improvement**: Processes for analysis, forecasting, estimation, and communication were directly improved, and value was extended to cost planning, reduction and control structures.

- **Communication**: Comprehensive communication will ensure continued momentum and awareness. Enhanced cost management practices are providing greater clarity for capital and expense investment drivers.

- **Consistency**: formal guidance documentation provides the guiding philosophy for cost management and provides an integrated framework and direction. Development of new training will ensure standardization in practice and support.

**Recommendation Number:  46**

As skilled people represent the cornerstone of the holistic approach, expand the role of cost management professionals to encompass tasks and accountabilities important to holistic cost management.  (Conclusion 5)

Team Lead(s): Nicholas Colonna / Robert Muccilo

**Summary of Implementation Actions:**

This recommendation is complete.

The team focused on increasing the skill sets and revising the duties associated with cost management positions. The team initially incorporated information obtained from both the benchmarking study conducted on active practices in cost management and the internal surveys. The team then assessed our current Performance Management system skill inventory to determine those skills deemed to be important to this function. Based on these sources, new position guides were developed for the Cost Management personnel for the following position titles: Analyst, Senior Analyst, Senior Planning / Financial Analyst, and Section Manager.

The following revisions were made:

- Analyst and Senior Analyst
  - Major responsibilities added:
    - Perform root cause analysis on cost categories with significant or unanticipated variations and determine corrective actions.
    - Work with and assist operating departments and interface with HR teams / Workforce Planning group in quantifying resource requirements.
  - Engineering experience added as preferred experience.

- Senior Planning or Financial Analyst
  - Major responsibilities added:
    - Act as team lead in developing action plans to enhance cost control in the operations.
    - Work with operating organizations to develop and track units of work cost measurements
    - Work with and assist Operating Departments and interface with HR teams / Workforce Planning group in quantifying resource requirements.
    - Provide support and interface with senior management on cost management issues to achieve common goals.
  - 5 plus years general accounting, planning and administration and budgeting added as required experience. Engineering experience a plus.
- Section Manager
  o Major responsibilities added:
    ▪ Develop action plans to enhance cost control in the operations.
    ▪ Perform root cause analysis on cost categories with significant or unanticipated variations and determine corrective actions.
    ▪ Plan and manage quantification of resource requirements through alignment with business leader's long-term workforce strategy.
    ▪ Provide advice and recommend necessary training to operating departments on all cost management matters.
  o 6-8 years general accounting, planning and administration and budgeting added as required experience. Engineering experience a plus.

Associated development and implementation of formal training programs and cross functional training for line and cost personnel is discussed in detail in recommendation 48.

The expansion of the roles and responsibilities of cost professionals, more stringent qualification requirements, and support for professional development of Con Edison cost professionals promotes the following initiatives in the Company’s enhanced, holistic cost management program:

- Formalize the Cost Management program
- Balance focus on reporting and root cause analysis
- Support Line Management
- Improve efficiency to optimize spending
- Communicate, communicate, communicate

Specifically, implementation of this recommendation achieved the following objectives and benefits:

**Objective:** Standardize position guides for cost management positions  
**Benefits:**
- Raised the minimum experience requirements for each position
- Elevated the skill set required for any cost management position in the company
- Standardized the duties and responsibilities across all cost management positions regardless of what organization they reside in
- Ensured that the duties and responsibilities in each position guide promoted the implementation of an enhanced cost management program

**Objective:** Develop a cost management career path  
**Benefits:**
- Career paths promise future professional opportunities
- Assist in recruitment and hiring activity
- Improve retention of employees
- Provide a developmental path for employees
The activities undertaken to achieve these objectives included: analyzing survey results; constructing Cost Management position guides; reviewing, developing and finalizing career paths; and renaming section names.

Total costs to achieve the implementation objectives were approximately $5,000. In addition to the qualitative benefits stated above, hard savings are expected to accrue as a result of this investment of time and coordination of effort. Benefits are expected to exceed the costs to implement this recommendation.
Recommendation Number: 47
Establish a cost support organization that is (a) placed consistent with the priority of cost management; (b) serves the cost management needs of all levels of management; (c) develops a force of skilled cost professionals and assures those skills are continuously improved; and (d) has overall accountability for the development and implementation of the cost management program. (Conclusion 5)
Team Lead(s): Nicholas Colonna /Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

Con Edison took seriously the advice of The Liberty Consulting Group and its recommendation for enhanced cost management oversight. Of key importance was Liberty’s observation that the “most successful cost organizations have featured a high reporting level, which immediately establishes the importance of cost and the credibility of the people,” and its suggestion that these cost professionals remain at the local level, reporting to a local manager, and that they should “have a ‘dotted line’ relationship back to the central cost management organization.” That centralized cost management organization “would then be responsible for...technical direction, supporting them with staff capabilities and providing training and career development.” These recommendations served as guiding principles of this organizational initiative and its resulting realignment.

At the time of the Management Audit, The Liberty Consulting Group observed a cost organization where cost management functions were centralized within the Planning and Analysis group; this group reported to the Engineering and Planning group within the Electric Operations organization, as shown below:

![Organizational Chart]

In this organizational design, while cost management functions were aligned with the goals of an integrated planning and analysis cycle, the priority of cost was not immediately obvious.
The Liberty Consulting Group’s innovative approach to the Management Audit gave Con Edison senior management opportunity to collaborate with the auditors and PSC Staff to discuss opportunities for implementation of this organizational alignment. In addition to those criteria cited in Liberty’s recommendation, this evaluation called for the identification and implementation of an organizational alignment that balanced:

- Consistency in policies and practices
- Alignment of activities to priorities and goals
- Oversight and direction
- Partnership with stakeholders
- Independence of cost management personnel
- Opportunity for employee development.

Satisfying these parameters would allow Con Edison to establish an enhanced cost organization, and in the process, create synergies with other ongoing cost management efforts.

Evaluation options yielded the conclusion that a position should be created, reporting directly to the President of CECONY operations, to champion cost management efforts. Con Edison took action accordingly, and created and staffed a “Director of Cost Management” position.

This cost management structure accomplishes Liberty’s recommendations by providing a matrix organization that establishes the priority of cost management, serves the cost management needs at all levels of management, supports the continued and consistent development of cost professionals, and supports the Company’s overall efforts to achieve greater excellence in Cost Management. Implementation of this organizational structure will be integrated with a broader framework and organizational assessment of Con Edison.

a) **Priority of Cost:** This new alignment ensures the high priority of cost management and consistency of communication across all organizations. The Cost Management Director is responsible for oversight of all facets of the cost management.

b) **Serves needs of all levels of management:** The centralized location of this new Cost Management organization ensures enhanced integration of input from all areas of CECONY and that needs from all business units and levels of management are addressed. A matrix relationship with line organizations is maintained, as recommended, to ensure direct input from this group’s customers.

c) **Continuously develops cost management skills:** Continued centralization of this organization ensures consistent work practices are adopted and continued.

d) **Overall accountability for cost management:** This realignment gives a clear path to the Director of Cost Management and establishes heightened accountability.

The creation and centralization of the Cost Management Director position has lead to a heightened awareness of and focus on the importance of cost. Increased cost management oversight resulted in a greater degree of vigilance and organizations have
focused more on pro-actively controlling costs. By developing and communicating the work plans in conjunction with the operating areas, the Cost Management group has been able aid them to better control costs. One organization had a $14.3 million dollar overrun in May 2009 which was reduced to an $8 million dollar under run by the end of December 2009. This was accomplished through the use of the work plans which were utilized in developing an overall cost reduction plan.

Cost management and line personnel are becoming increasingly involved in pro-actively managing cost as is evidenced by the previously cited examples. The creation of a centralized Cost Management Director position has lead to a higher priority of cost, increased feedback and oversight.
Recommendation Number: 48
Provide training for managers, supervisors and cost support personnel in cost management techniques consistent with the holistic approach. (Conclusions 1, 5, 6)
Team Lead(s): Nicholas Colonna / Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

To establish a baseline of available training, all classes available at Con Edison’s professional training center (The Learning Center) and through external parties were catalogued. A detailed training matrix was then developed for each level of cost management professional and also for line personnel. This matrix listed all available classroom, on-the-job, technical, and outside training courses, as well as certification classes. The training matrix was updated based on the feedback received from the internal surveys and the third party consultant; this work was done by the same team that assessed the roles and responsibilities for cost personnel for Recommendation 46. It is available to both cost and line personnel via the Finance Web Portal. It identifies all training required to enhance the skills of both cost and line personnel with regard to cost management. The matrix will also assist managers in developmental planning for their staff during performance reviews.

A team consisting of cost management, line and human resource personnel was put together to create a new course for educating managers and supervisors in cost management techniques. Initially, it is being implemented as an instructor-led class and will be delivered as an eLearning course to line managers and supervisory personnel.

The course defines “holistic cost management” and the role of the manager and supervisor in the process. It explains the development of the work plan and the budget planning process. It details important factors that impact cost and will provide managers and supervisors with a framework in which to better manage and control cost. The importance of proper planning, scheduling and managing of work is also discussed as part of this course, as are the tools and resources available. Additional courses will be referenced as part of this training.

Content from this course will be integrated into leadership-oriented courses to strengthen work oversight and proactive planning approaches to cost management.

The costs in achieving these objectives totaled approximately $8,000; we expect to achieve savings greater than this cost and also for the continued cost of training. Providing training for cost professionals and line personnel advances the Company’s effort to adopt an enhanced approach to Cost Management. Specifically, building the skill sets of these key players will support the Company’s initiatives to:
• Formalize the program
• Balance focus on reporting and root cause analysis
• Develop alternatives and action plans
• Support line management
• Actively improve efficiency to optimize spending
• Provide continuous communication
Recommendation Number: 49  
General Recommendation Implementation Guidance. (Cost Management program)  
Team Lead(s): Nicholas Colonna /Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

The implementation team used this recommendation as an opportunity to establish an analytical best-practice and structure for project and program cost analysis. As suggested in the recommendation, the team broke the cost structure of a sample project down into major cost elements or packages and then graded each for its “manageability;” it assigned cost responsibility to an individual for each element, required a specific cost management plan for each element and created a project-unique reporting system based on the elements.

To serve as an early warning mechanism, as stated in the recommendation, the team developed the “Budget Reference Appropriation vs. Project to Date Costs” report. This report is also commonly referred to as the “70% report” as it alerts the report viewer all of the projects where the actual costs have reached or exceeded 70% of the appropriated dollars. This 70% threshold is customizable and can be modified as desired by the report user.

The 70% report is currently being used by Electric Operations for new business, burnouts and system reinforcement projects, and will be expanded to include other areas. By showing the viewer the actual project-to-date expenditures as well as the appropriated dollars, report users can incorporate the committed dollars along with comparison to field completion status to fully prepare and understand a project’s total Current Working Estimate (CWE).

A new initiative is in progress to track the details, by work order (a numerical account used to track costs) and layout number (part of the work package), of all projects that have reached or exceeded the user-defined threshold above. This report will incorporate engineering estimates and appropriated dollars / units from Distribution Operations Control System (“DOCS” – Electric Operations’ current work measurement system) for each project and combine them with actual project-to-date data to enable unit cost comparisons. It will also provide users with the capability to estimate the amount of work remaining and also calculate the CWE in a different format than noted above.

The analytical methods followed through implementation of this recommendation represent best-practices to proactively track, plan, manage, and respond to project and program costs. The processes and tools as outlined will become the foundation for cost management tracking for projects, and along with their exhibits, they will become part of
various existing training courses such as “On Budget” and “Advanced Topics in Project Management.” Beyond the scope of this recommendation, the Team is establishing webpage content that will incorporate the full guidance and approach for effective cost management.

The following benefits could be gained by timely reporting and analysis of elements of cost for a project or program:

- **Avoidance** - Early detection of potential risk to cost provides an opportunity to avoid lost productivity resulting from the investigation, identification and analysis of reasons for overruns
- **Better understanding of costs impacting project’s schedule**
- **Better long term planning for more accurate cash flows, schedules and budgets**

In-depth timely analysis for tracking project cost by element of expense will result in inherent savings and a potential reduction in project overruns. The savings is the avoidance of justifications and detailed project cost analysis needed to support appropriation increases. These cost analysis practices provide methods for early detection of cost overruns and can also be used to evaluate the impact of a scope change or increase.

The cost for developing this recommendation was approximately $50,000. The expected savings as a result of the widespread application of the processes and tools implementing this recommendation will exceed this cost.
Recommendation Number:  50
Sample Cost Management Implementation Tactics. (Cost Management program)
Team Lead(s):  Nicholas Colonna /Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

The recommended “Cost Management Implementation Tactics” have implemented as part of the Company’s implementation of a holistic approach to cost management. For implementation detail, please see recommendation 45.
Recommendation Number:  52
Perform in-depth reconciliation on cost estimates with substantial overrun to better understand the root causes of deviations. (Conclusion 9)
Team Lead(s): Nicholas Colonna /Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

We have developed a new variance template to provide a more effective tool for cost analysis. The new report now provides analysts with not only expenditures, but unit of work and man hour variances from the budget. This new tool shortens the amount of time analysts need to spend gathering data for analysis and gives them more time to develop a plan to meet budget goals.

In addition to more data provided to Analysts, the improved variance reports also include automatically generated questions based on variances in expenditures, unit cost and hours per unit data for different work activities. These questions provide a structured thought process and consistency in analysis of cost drivers. The generated questions inquire as to “why” the variance happened, whether a change of course is necessary, and what is being done to meet monthly and year to date goals. The questions provide a framework for action oriented thinking that with normal use will engrain itself into the culture of the Company. These questions establish a line of communication between the analyst and the field personnel that promotes cost management by line organization business units and collaboration between analysts and the Section Managers in better managing business unit costs.

The report issues questions for each work activity that has a significant variation from the budget. There is room for a response and an action plan for getting back on target.

An “Estimate vs. Actual” report has been developed as a tracking and reporting tool to promote more active management of capital expenditures. In these reports, project costs for large capital projects are reported as they are incurred, and actual cost information is compared to the estimated cost created at the time the project was appropriated.

Direct benefits can be achieved through use of the Financial Internet Portal, enhanced variance templates, Estimates vs. Actual report, and Lessons Learned from reconciliation of appropriations. Most significantly, the following benefits could be gained by an insightful project reconciliation that will identify the major cost drivers and what could have been done differently:

• Better understanding of lessons learned; higher sensitivity to costs.
• Better long term planning for scheduling and budgets
Cost savings: Incorporating the lessons learned and the additional work in the design stages of projects to ensure a more accurate scope of the project requirements, results in an incremental cost of approximately $23,000. This was derived by estimating the cost to hold Lessons Learned meetings; prepare, review, comment and finalize the report and perform additional activities during the design phase of the project.

To have a positive impact on the Company savings of approximately $23,000 would be required to offset the costs discussed above. Therefore if the average cost of a project that requires a second appropriation is $3,000,000, a savings of 0.76% would be required to break even. Since we expect to achieve savings of at least 1% of the total project cost by utilizing the more formal program management process and tools, we expect a positive cost benefit for the Company and its customers.
Recommendation Number: 62
Prepare an analysis of corporate overtime expenditures that includes root causes of the upward trends and strategies for attaining more economic levels. (Conclusion 9)
Team Lead(s): Nicholas Colonna / Robert Muccilo

Summary of Implementation Actions:

This recommendation is complete.

Overtime expenditures were summarized to ascertain trends over several years from 2003 - 2009. These expenditures were then compared to actual capital expenditures for the same period. The comparison indicated a direct correlation to the increase in overtime expenditures. We reviewed the system emergencies and events which transpired within the same time-frame. Overtime expenditures did increase in accordance with these events. Required work resulting from these events also led to increased overtime use and spending.

Analysis indicates that both of these factors – work volume and efficiency – influenced increased spending for overtime. Some of the major causes of overtime use and the upward trends during the period from 2003 through 2009 are further detailed below:

- **Increased quantities of work:**
  - During this period, electric, gas and steam capital expenditures for addressing customer demand and reliability increased from $0.9 billion in 2003 to $2.2 billion in 2008, an increase of 69% over the period.
  
  - In 2004 and 2005, the Public Service Commission issued mandates regarding (1) the response time to the backlog of street light outages and, (2) the frequency and number of annual tests related to stray voltage and annual inspections related to electric equipment. Although overtime was required to address the immediate needs, the work in these areas has since been reduced to levels that are more readily supported with the existing workforce.
  
  - In 2006 and 2007 the Company incurred increased levels of emergency response work attributable to the Long Island City outage and the Steam Pipe Explosion incident. The extensive restoration and system reinforcement relating to these incidences increased work above planned levels. This high level of work continued on a discretionary and/or contingency basis to prevent or avoid the reoccurrence of these operating events. In addition, significant weather related events increased the level of overtime for emergency response and infrastructure restoration above planned levels.
• **Efficiency impact resulting from a significant number of new hires:**
  o During the period 2003 through 2009, the Company experienced a high level of attrition that required the hiring of inexperienced workers. Although hiring has outpaced the rate of attrition, productivity declined due to training requirements and inexperience. Both the Company’s training efforts and increased focus on productivity initiatives have contributed to the recent declines in the use of overtime. The affect of this efficiency impact is expected to decrease with growing experience of this new hire population.

In 2009, the Company had no major weather related events or incidences and had begun realizing some benefits from the initiatives discussed below, resulting in the reduction of overtime expenditures from a high of $134 million in 2008 to $106 million in 2009, which is a reduction of 26%.

Several factors contributed to the decrease in overtime. There is more focused evaluation on the economic use of overtime use including improved work planning and scheduling. Increased efficiencies in planning and execution of work will result in reducing the time required to complete work activities including the level of overtime hours. In 2009, the Company implemented weekly monitoring reports of where overtime is being utilized - i.e. emergency response versus planned work. This increased attention has allowed operations personnel to focus on decreasing the use of overtime after events or emergencies have subsided. In 2010, organizations have implemented, as a performance indicator, metrics for using overtime compared to straight time hours. These metrics also drive operating organizations to evaluate the economics in using overtime since it impacts the specific measure. As noted in recommendation 61, these metrics will continue going forward.

The significant downturn from 2008 to present indicates success of initiatives to better control and manage overtime.

Goals for overtime are established in the budget planning process, wherein work plans are matched to workforce capability and financial and operational constraints. These budgets are continuously tracked, monitored, and referenced as targets, and performance to these targets is reported and openly communicated on a monthly and year-to-date basis.

In tandem with the Company’s current efforts, a guidance document has been developed to address the administration and management of overtime use. This guidance document promotes strategies for attaining more economic levels of overtime use, and is described in greater detail in recommendation 61. This guideline establishes uniform standards for overtime budgeting, exception reporting and tracking across the Company, and also provides guiding principles for cost control and mitigation measures, including identifying the drivers for overtime expenditures and developing a plan for returning to budget or established target levels.
Additionally, efforts to measure, monitor, and mitigate the productivity impacts of on-the-job trainees are aided by the use of a specific work code (AE0160) to be used in daily time reporting of on-the-job training time in Electric Operations and the development of a consistent guideline document for monitoring and assessing the productivity and cost impacts of carrying an extra trainee, as discussed in recommendation 54.
Recommendation Number: 65
Implement a formal program for representatives from each region to share lessons learned in their respective fields. (Conclusions 4, 9)
Team Lead(s): Nicholas Colonna / Robert Schimmenti

Summary of Implementation Actions:

This recommendation is complete.

A structured Lessons Learned Program has been developed and implemented to identify, document and communicate Lessons Learned. The enhanced Electric Operations Lessons Learned program establishes a Lessons Learned Team and provides a process for meeting quarterly to identify, discuss and communicate Lessons Learned. Each meeting is sponsored by an Electric Operations General Manager, and includes representation from each region, as well as Energy Services and Construction Management. Meetings are framed around decisions for adoption of specific Lessons Learned, and include discussions on quantified cost savings or avoidance.

Lessons Learned are documented and reported to the Lessons Learned Team based upon a common structure. This “Lessons Learned Report” template includes:
- Problem description
- Problem Resolution and Preventive Actions
- Implementation Effort and Costs

This structured report template is posted to an internal Electric Operations SharePoint site created to be a library of Lessons Learned along with guidelines for reporting and sharing Lessons Learned and use of resulting documentation.

The cost of the Lessons Learned Program is the development of the SharePoint site and the quarterly meetings of the Lessons Learned Team; the initial cost was approximately $3,000 and the annual cost is expected to be $4,000. To have a positive cost-benefit impact, cost savings or avoidance need to exceed the initial cost of the SharePoint Site and the annual cost of the quarterly meetings. We anticipate savings will exceed the costs of implementation for this effort.
**Recommendation Number:** 68

Improve resource planning for design personnel and other essential project personnel.

(Conclusion 3)

**Team Lead(s):** Nicholas Colonna / Frank Lembo

**Summary of Implementation Actions:**

This recommendation is complete.

We have reviewed the "lessons learned" reviews from 14 major projects mentioned in the Liberty audit report. These were taken from projects in the 2005-2007 time period. We evaluated and addressed all the major findings. Most of the audit report findings were already being addressed based on internal recommendations and continuous improvements which were implemented since the project review period.

Central Operations has developed a project management organization structure, has established relevant training curriculum and requirements, and has increased staffing by 20% over the 2005-2009 period. Staffing of our Technical Coordinators who interface with our outside Design & Engineering contractors has increased during this same period. Dedicated teams are assembled for large projects, and a transitioning responsibility checklist has been added to formalize the process and minimize the impact of change in essential team members.

The Engineering Operating Manuals or "EOM's" serve as the vehicle for the management of Central Operations’ projects and programs including development, planning, implementation, and closeout. To ensure successful project and program management, Central Operations has established a comprehensive training module for new hires.

Procedural documentation was updated for checking of the design packages. This procedure will require an independent checker for all design packages (preliminary and final) which will improve the quality of the construction packages.

Enhanced oversight and process improvements will upgrade the quality of design work performed by outside services.

Issues with late arrival of vendor drawings are being addressed by the development of standard interface drawings. The importance of timely receipt of “as built” drawings is being emphasized with our customers and outside services. Development of detailed scopes and the early involvement of our customers in the scoping and design phases are also being stressed.

The following tasks were completed in responding to this recommendation.
• Reviewed projects used in Audit and identify any deficiencies.
• Determined range of staffing level increases to address the issues and evaluate the economical and technical benefits or lack thereof for increased usage of in-house or Architect/Engineering (A/E) resources.
• Evaluated expertise of in-house and A/E resources.
• Reviewed feasibility & relative merits of dedicated project teams (one job at a time) vs. project magnitude.
• Evaluated the effects of external influences on successfully completing Engineering Design activities.
• Evaluated the effects of other company organizations’ support to Central Engineering.

After conducting a survey and evaluation of level of expertise, education, technical qualification, quality of work and economical benefits of in-house personnel vs. outside contractors, we concluded that the following benefits could be gained by the reduction of the outside services design budget and the increase of in-house design personnel:

• Better quality packages based on the users’ feedback on various type jobs
• Sustainability of in-house expertise to be able to handle day to day operation and emergencies
• Cost savings of 25% through increased efficiency and productivity

Increased productivity is achieved through the use of templates and application of new technologies. The productivity initiatives are also incorporated into Design Engineering KPI’s for breakers and disconnects switch replacement programs and is measured based on hours/drawing.

We have evaluated similar jobs done in-house and with our A/E firms to determine productivity and cost benefits of using in-house personnel to produce Engineering Design packages; evaluation of this sample showed a realized savings of $1.0 million achieved with the use of in-house resources. This evaluated cost savings is sustainable, and based upon jobs projected in the 2010-2014 budget, are projected to equal $273,000 annually.
**Recommendation Number:** 69
Bring a corporate total holistic approach to cost management to the project and program management efforts. (Conclusion 6)

**Team Lead(s):** Nicholas Colonna / Timothy Ryan

**Summary of Implementation Actions:**

This recommendation is complete.

The Audit Report found that the project management process within Central Operations already contains several aspects of the holistic cost management approach. The Report stated “One aspect that has not been observed is a cost analysis of the changes made in response to lessons learned. Having this available would establish the place of cost in the hierarchy of priorities and drive the organization towards more rapid action.”

To further strengthen the holistic approach within project/program management in Central Operations, cost analysis has been incorporated into the Lessons Learned phase of the project. Knowing the cost benefit associated with best practices identified during this process will provide a better understanding of the value of including these changes into future projects. In an effort to ensure that a cost benefit analysis is incorporated into the existing lessons learned process, the Lessons Learned template has been revised, communicated, and issued to assist the project team in developing their Lessons Learned.

Incorporating this enhanced Lessons Learned process results in an incremental cost of approximately $21,000 per project. This was derived by estimating the cost to hold Lessons Learned meetings; prepare, review, comment and finalize the report and perform On-the-Job Training (OJT) as follows:

- Lessons Learned Meeting – 160 man-hours (includes the preparation, resources and holding the meeting)
- Prepare/Review/Comment/Finalize Lessons Learned report – 30 man-hours
- Perform OJT – 110 man-hours

To have a positive cost-benefit impact on the Company, and therefore its customers, the $21,000 cost (which includes the itemization and consideration of cost associated with improvements/impacts) of implementing this enhanced Lessons Learned process must be less than its resulting project cost savings. This implies, for example, that the required break-even savings to justify implementation for a $15 million project is 0.14% of total project cost, and furthermore that for projects with costs greater than this sample $15 million project, the $21,000 cost of implementation will potentially have an even greater positive impact when compared to project cost. Since we expect to achieve savings beyond this incremental cost, we expect a positive cost benefit for the Company and its customers.
Recommendation Number: 70
Strengthen Substation Operations program management processes by adding project management principles in a structured way. (Conclusion 18)
Team Lead(s): Nicholas Colonna / Timothy Ryan

Summary of Implementation Actions:

This recommendation is complete.

Substation Operations (SSO), in an effort to establish a more formal approach to its program management processes, pursued several actions. One effort was to assign project engineers, lead discipline engineers or other qualified individuals as the Central Engineering Point of Contact to each program category within the Capital portfolio, as indicated in the “SSO Program Management Teams – Core Members” document. They have been tasked with managing all engineering aspects of the program, which allows for better work process flow and schedule support.

Also, the frequency at which Current Working Estimates (CWEs) for each project within a program will be prepared and disseminated has been developed. CWEs are now being prepared and sent to program team members at the frequency noted in the document attached (“CWE Frequency”). These CWE’s will serve as the basis for financial performance review and discussion among program team members, and will be used to closely track performance of individual projects within each program line. Variances will be evaluated and appropriate action taken to ensure that programs are progressing within the desired expectations.

Another action was to develop project teams similar to those developed for the larger construction projects. These teams include representatives of Planning, Engineering, Finance, and the various working groups involved in the programs; their responsibilities are in-line with Corporate Procedure COP 10-0-5. Periodic review meetings with the program teams have commenced and will continue to be held to ensure that the program expectations are being met and appropriate strategies developed in order to address any shortcomings. These meetings will focus on topics such as schedule compliance, resource availability, and financial performance. An example of this is provided in the attached project team meeting minutes support documentation. See file titled “Analog Circuits to Digital Fiber Program Meeting 13 Jan 2010.” Financial performance discussions are expected to focus on CWE performance versus estimates. Significant overrun or underrun conditions will be analyzed to determine root cause and required corrective actions. Due to the recurrence of similar projects or work types that are common in program lines, the information gathered from these reviews will also be useful in developing plans and financial expectations for future jobs. Candidate projects will be reviewed for inclusion in the various programs, with a focus on ensuring that work being done under the program is cost justified, and is being given the proper priority.
The incremental costs associated with implementing this recommendation are estimated at approximately $1.29M annually. These costs include periodic team meetings, increased CWE activity to meet deliverables schedule developed and the assignment of Program Engineers to all SSO programs.

To have a positive cost-benefit impact on the Company, and therefore its customers, the $1.29M annual cost of implementing these enhancements to the Program Management process must be less than its resulting project cost savings. This implies that the required break-even savings to justify implementation for the sum total of SSO programs is approximately 1%. This is based on the approximate capital spending levels for SSO Programs over the next 3 years, which are roughly $126M in 2010, $156M in 2011, and $190M in 2012. Since we expect to achieve savings of at least 1% of the total project cost by utilizing the more formal program management process, we expect a positive cost benefit for the Company and its customers.
Recommendation Number: 73
Implement a corporate total holistic approach to cost management. (Conclusion 6)
Team Lead(s): Nicholas Colonna / Robert Schimmenti

Summary of Implementation Actions:

This recommendation is complete.

This recommendation has been completed as part of the Company’s implementation of a holistic approach to cost management, discussed in recommendation 45.
Team 6 – Load Forecasting
Executive Sponsor: Luther Tai

Recommendations: 14, 16, 17, 18, 19, 20, 23, 79, 80, and 82

Recommendation Number: 14
Analyze, and redirect as appropriate, the level of effort and sophistication applied to various load forecasting tasks and products, to better balance costs with product and user needs.

(Conclusion 2)
Team Lead(s): Joseph Oates / John Mucci

Summary of Implementation Actions:

This recommendation is complete.

Benchmarking was performed with other utilities to obtain information on their forecasting methodologies, inputs, assumptions, and models. The benchmarking allowed the Company to see how others are forecasting their peak demand and sales in order to make potential improvements/changes to the current processes that can allow for a shift in resources. Some best practices from the benchmarking effort are discussed in Recommendation 23. The benchmarking is also being used to evaluate the use of load research data as part of the Company’s implementation effort in recommendation 20. Forecasting also developed training manuals that describe the forecasting processes in order to utilize them as a training tool when there is staff turnover or for a member of forecasting to learn a new aspect of the forecasting area.

Forecasting redirected some resources to generate long term forecast scenarios. The forecast scenarios developed were primarily for use in the Electric Long Range Plan (ELRP). The Demand Forecasting and Revenue and Volume Forecasting groups worked with external subject matter experts (McKinsey & Co; Bridge Strategy Group, LLC) and other internal company experts, to develop three 20-year load forecast sensitivities that have been used in the development of the ELP. The sensitivities include the impact of economic assumptions, energy policies, demand side management, and new technologies, such as electric vehicle penetration, in the Company’s service area.

Some tasks have been eliminated within Demand Forecasting to free up resources for other functions within the section. The staffing level within Demand Forecasting has remained the same, which has allowed for the shift of resources that will permit Demand Forecasting to enhance the resources available for core forecasting functions such as long-term planning. For example, the Demand Forecasting group is also participating in the development of both the Gas and Steam long range plans.
There were no additional costs identified at this time to implement the recommendation. By implementing this recommendation, the Company’s forecasting groups eliminated and streamlined tasks, and in so doing, freed up resources for developing sensitivities for the Electric Long Range Plan and supporting more “what if” studies (for example, the impact of electric vehicles on electric network demand and infrastructure needs). These new sensitivities should result in a more robust planning process that further considers the impact of economic assumptions, energy policies, and changes in trends and new technologies. The analysis conducted to implement load forecasting recommendations is in-line with our principle to improve continuously and seek ways to refine the demand forecasting process.
Recommendation Number:  16
Conduct an R&VF review of certain aspects of its approach to forecasting. (Conclusions 9, 13)
Team Lead(s):  Bob Muccilo

Summary of Implementation Actions:

This recommendation is complete.

Revenue and Volume Forecasting (R&VF) has completed the review of its approach to forecasting. To identify potential areas for improvement, Revenue and Volume Forecasting applied three approaches. First, ex-post forecast performance analyses were performed to determine if the sample range used in the electric volume forecasting models, and the model used in determining employment effect on gas delivery volumes, should be changed. Second, other utilities were surveyed to benchmark the Company’s practices against industry norms. Third, econometric theory was considered. Combining the results of the ex-post forecast evaluations with those from the benchmarking exercise and adding the theoretical considerations of criteria for consistent estimation of the models led us to conclude that there is no significant advantage to altering either the Company’s current practice of using 25 years of historical data to estimate its electric volume forecasting models or the process by which the employment effect on gas delivery volumes is determined.

In the ex-post forecast performance analyses, we compared the forecast performance of current Company electric volume forecasting models against models that were estimated using various sample ranges (i.e., 10, 15, 20, 25, and 30 years) and two forecast ranges (i.e., one year and two years). The models that were evaluated include the models for sendout and the larger SCs, namely SC 1 (Residential), SC 2 (Small Commercial), SC 4 (Master-metered Commercial)\(^1\) and SC 9 (Large Commercial). The results indicate that shorter time frames do not necessarily provide better forecasts, as measured by variance from actual volumes.

An electric benchmarking study of the forecasting process was also conducted. The results of the survey, in relation to the sample range used in the econometric models used to forecast electric delivery volumes, indicate that most utilities we surveyed do use less than 25 years of historical data in their forecasting models.

Econometric theory states that there must be sufficient data to provide at least thirty degrees of freedom\(^2\) to ensure consistent results. Many of the other utilities use monthly models with 10 to 15 years of data, which provide them with more than sufficient degrees of freedom for consistent estimates. Given the number of explanatory variables and the autoregressive and

\(^{1}\) As of April 2010, SC 4 has been merged into SC 9. At the time of this study, however, the forecasts for SC 4 and SC 9 were done separately.

\(^{2}\) The number of observations less the number of parameters to be estimated is referred to as the degrees of freedom in estimation.
moving average terms in the Company’s quarterly forecasting models, however, a 10 year sample range may not provide the necessary degrees of freedom.

Another important theoretical consideration is that the historical data have to include at least one episode of significant economic downturn in order for the model to adequately capture the impact of economic downturns on electric delivery volume and hence be able to incorporate such impacts in forecasting volume when economic downturns are expected in the future. Since the last major downturn in the economy occurred from 1990 through 1992, the sample range must be at least 20 years to include that downturn.

Combining the results of the ex-post forecast evaluations with those from the benchmarking exercise and adding the theoretical considerations lead us to conclude that either a sample range of 20 years or one of 25 years is optimal for the Company’s electric volume forecasting models. Thus, the Company’s current practice of using 25 years of historical data to estimate its models is not unreasonable based on the above analysis.

Our review of the process for determining the employment effect on gas delivery volumes began with a study of the effect of changing the sample range of the econometric model by estimating the current gas model for SC 2 using alternate sample ranges of 10, 15, 20, 25, and 30 years respectively. Each sample range produces a separate forecast of the employment effect on gas delivery volumes. The forecast of SC 2 delivery volumes associated with each sample range is then compared against actual weather-normalized delivery volumes to obtain the variation of the forecast from actual volume. The results indicate that changing the sample range produces no significant difference in the employment effect.

As part of the review, alternate formulations to the current SC 2 model were also studied, and the forecast evaluations of alternate sample ranges were applied to the alternate models. The alternate models considered include models where the employment variable in the current SC 2 model is replaced by a different economic variable like real disposable personal income or real gross city product. The results from the alternate models confirm that the size of the sample used to estimate the impact of economic changes on SC 2 delivery volumes did not matter. Comparing the results across the different models, we find that the alternate models produce no improvement over the current.

In the Company’s current process for forecasting gas delivery volumes in SC 3 (Residential), the volume forecasts take into account changes in the projected number of residential customers, but assume that employment and other economic variables have no significant effect on SC 3 delivery volumes. In this review, we tested that assumption by estimating econometric models similar to those currently used for SC 2. That is, we estimated econometric models that relate SC 3 delivery volume to price, number of residential customers, cycle heating degree days, seasonal indicator variables, and an economic variable, using the same sample ranges of 10, 15, 20, 25, and 30 years. The economic variables considered were employment, real disposable income, and gross city product. Each is used separately, in turn, in the econometric model. The results show that, regardless of the sample range and economic variable used, the t-statistic on
the coefficient did not exceed the critical level of 1.96\(^3\) in absolute value, which implies that the economic variable did not have a significant independent effect on SC 3 delivery volume.

A benchmarking study of the gas forecasting process was also conducted. The results of the survey, in relation to the methods used in the volume forecasting process, indicate that most, but not all, utilities that were surveyed use either linear regression or econometric models in their forecasting process. There does not appear to be a consensus on the sample range because the range used depends on the forecasting method, frequency of the data, and data availability. The methods used to determine the effect of employment, or other measures of economic activity, on delivery volumes were also varied. While some utilities determine the employment effect through econometric models, others determine the effect indirectly through their customer forecasts.

The same theoretical considerations as discussed in the electric forecasting section above apply to gas forecasting as well.

The forecast evaluations conducted on the Company’s current SC 2 model indicate that the delivery volume forecasts produced by the estimated coefficient on the employment variable are not significantly affected by the sample range used to estimate the relationship between the employment variable and delivery volume. When the analysis is repeated on alternate formulations of the current model, the sample range did not matter. There is also no improvement to be made by changing the variable used to proxy the level of economic activity. Hence, the Company will continue to use the current formulation and sample range of the SC 2 model.

The analysis of possible SC 3 models indicate that economic variables do not have significant effects on delivery volume. Thus, no change to the current forecasting process for SC 3 delivery volume is proposed.

In response to a request from Staff, R&VF expanded the review of its forecasting processes to include: (1) tests for structural change in the electric volume forecasting models during the 1983 – 2008 historical period, (2) a 5-year ex-post forecast evaluation of the electric commercial volume forecasting models, and (3) an analysis of the impact resulting from a change in sample size on the constant term in the electric SC 1 model.

**Tests for Structural Change**
A structural change in an electric volume forecasting model is defined as a change in one or more of the model parameters from one sub-period of the sample range to another. To test for such changes, the Quandt-Andrews Breakpoint Test for unknown breakpoints was applied to the Company’s major volume forecasting models, namely SCs 1, 2, 4, 9, and Sendout. Our review indicates that structural changes exist in the SCs 2, 4 and 9 models. For example, there was a change in the intercept term, which represents the underlying growth in delivery volume.

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\(^3\) Based on the usual statistical standard of a 95% confidence level.
that is not captured by the variables included in the model, for SC 9 in the 2\textsuperscript{nd} quarter of 1992. Accordingly, commercial volume forecasting models that account for structural changes will be considered for use in future forecasts.

\textbf{5-year Ex-post Forecast Evaluation}

Our current practice is to use only the 25-year sample range for forecasting delivery volumes. The 1-year and 2-year ex-post forecast evaluations support this. To be consistent, the long range commercial volume forecast that the volume forecasting group provides to the demand forecasting group is based on the 25-year sample range. The 5-year ex-post forecast evaluation of the electric commercial volume forecasting models, however, shows that the 10-year sample range provides the forecasts with the smallest variance from actual volumes. Thus, long range commercial volume forecasts based on both 10-year and 25-year sample ranges will be provided to the demand forecasting group in the future.

\textbf{Constant Term Analysis}

The constant term in the SC 1 model represents the underlying growth in delivery volume that is not captured by the variables included in the model. To address the concern that the constant term in the SC 1 model is too high when a sample range of 25 years is used, we re-estimated the model using alternative sample ranges of 10, 15 and 20 years. Our review determined that the constant term in the SC 1 model does not change significantly when the size of the sample changes. When a 10-year sample range is used instead of the current 25-year sample range, the constant term is slightly higher. Thus, this analysis supports the Company’s current use of a 25-year sample range for the SC 1 model.
**Recommendation Number:  17**

Evaluate the factors responsible for consistently under-estimating 5 and 10 year peak load forecasts; assure that any bias is removed from future forecasts. (Conclusion 14)

Team Lead(s):  Joseph Oates / John Mucci

**Summary of Implementation Actions:**

This recommendation is complete.

Demand Forecasting analyzed several inputs to the five-year forecasts for each period beginning with the years 2002, 2003, and 2004. This information was used to gauge some of the causes of the under-estimation bias for the 5-year forecast.

We identified some trends that appear to be the source of the under-estimation bias. We identified an under-estimation bias in both the residential and commercial sectors, with the larger under-estimation occurring in the residential sector. The primary inputs into the demand forecast that lead to the under-forecasting bias in three 5-year forecasts we examined were the appliance saturation forecast, the household forecast, and the forecast of U.S. Gross Domestic Product (GDP).

With regard to the under-estimation of saturation of particular appliances, part of the cause of the under-estimation was due to the strong economic growth of the mid-2000’s which contributed to consumers spending more on appliances such as air conditioners, computers, televisions and electronic devices, as well as dishwashers, washing machines, and dryers. Since the trend for under-estimation lies mostly with these appliances, assumptions going forward will be more closely scrutinized and evaluated to minimize their contribution towards under-estimation of the five-year and ten-year ahead forecasts. The Company will also exercise caution to avoid an over-estimation to compensate for past performance, especially now that the NY economy has been suffering from an economic downturn since 2008, which may cause lower growth in some of the these appliances moving forward.

In addition, the household forecast experienced an under-estimation for these forecast years. We attribute some of this under-estimation to the housing boom that occurred in the mid to late 2000’s which increased the supply of homes by more than predicted five years earlier in 2002, 2003, and 2004, respectively. In fact, the number of building permits issued in the service area increased considerably in 2005, 2006, and 2007, with some of these additional households potentially showing up in 2006, 2007, and 2008 and causing an unpredicted increase in the peak demand. Another reason for the under-estimation is due to the household forecast that we used from Moody’s Economy.com. In its household forecast, Moody’s Economy.com revised upward the historical household data, thus raising the base number used by future growth estimates to forecast the number of households.
The result was the household forecast was now higher because of a revision in historical data.

U.S. GDP is utilized in the commercial econometric model that produces the sales forecast which is converted to peak demand. It is one of several inputs to the model which is provided to the Company’s Accounting Department to develop the model. The U.S. GDP forecast is provided by the Blue Chip Economic Consensus report. There was an under-estimation of the level of US GDP in real chained dollars for several reasons. One reason is due to the fact the base year for the U.S. GDP numbers was changed from 1996 dollars to 2000 dollars in 2004. This change increased the historical numbers and would, by default, increase the forecasted numbers if positive economic growth was still forecasted, which it was at the time. The second root cause for the under-estimation was the fact that economic growth was being forecasted without knowing an economic boom would occur in the U.S. in the mid 2000’s, causing GDP to grow at a healthy rate up through 2008. Even despite the recent economic downturn, the 2004-5 year ahead GDP forecast (for 2009) might still be under-forecasted since the growth rate has been consistently healthy and positive during the economic boom and due to the adjustments to the data mentioned above. While the Company cannot avoid a re-estimation of economic data since it does not control the data, one possible remedy to prevent an under-estimation could be to look at the U.S. GDP forecasts from Moody’s Economy.com as well as another vendor to see if their forecasts are aligned. Blue Chip Economic Consensus is used as part of a long-standing agreement with the Public Service Commission.

With respect to the under-estimation bias for the 10-year forecasts beginning with years 1997, 1998, and 1999, the same rationale for under-estimation holds true. In our analysis we found that the residential sector forecast did not include all the appliances that were included in more recent models. For example, computers were not in the model back in the late 1990’s. This appliance was added to the forecast in 2002, and the lack of this appliance in the earlier years was a contributor to the under-estimation in the residential sector. Although the appliance was added to the forecast in 2002, the speed of its growth was under-estimated as discussed in the five-year under-estimation section above.

Another factor that may have impacted the ten-year under-estimation bias was a re-benchmarking of the residential appliance information in 2002. Re-benchmarking involved asking additional questions in a telephone survey about appliances other than air conditioners that are not asked on a regular basis in the survey in order to re-estimate the information based on current data. The information obtained from the re-benchmarking caused revisions to some of the assumptions about appliances and increased the rate of growth in the residential demand for the year of the re-benchmarking (Y) as compared to the year before the re-benchmarking (Y-1). This also would have caused an under-estimation for the 10-year ahead forecasts developed before 2002 since the growth in the year Y due to the re-benchmarking would not have been known years earlier when the ten-year ahead forecast was being developed. Year Y became a higher starting point for forecasts going forward.
In addition, since the historical economic data for households and U.S. GDP were re-estimated resulting in an increase, the data used to forecast these indicators back in the late 1990’s prior to these revisions, caused an under-estimation of the 10-year ahead forecasts ending in years 2007, 2008, and 2009.

Another factor that contributed to the under-estimation was the inability for economic forecasters to predict an economic boom in the housing market of the magnitude and scope experienced in mid-2000’s. Even despite the economic downturn experienced in 2008 and 2009 in the housing market, the forecasts for these years may still be under-estimated since growth during the economic boom prior to 2008 and 2009 was so strong and the historical data were revised upward.

The scenarios that will be developed by Demand Forecasting will account for different economic outlooks to gauge their potential impact on the peak demand.

To prevent a forecasting bias, the Company will undertake the approaches outlined in this recommendation response, as well as in of the response to the other load forecasting recommendations, to provide multiple forecast scenarios, research and/or test new models, and evaluate forecast input assumptions. The annual update of the demand forecast permits evaluation of changes to see if they impact the forecast even on a year-over-year basis.

**Supplemental Completion Update:**

Pursuant to our discussions with Staff, analysis was conducted on additional factors that could have played a role in the under-forecasting bias. As a result of the discussions, we agreed to examine coincident usage, load factor, number of commercial customers, and the price of electricity.

**Coincident Usage**

With regard to the forecast for coincident use of particular appliances, we analyzed the three 5-year ahead forecasts beginning with years 2002, 2003, and 2004. These years were chosen because data was available and these are the same forecast time periods as the variables discussed in the Completion Summary above.

We found that the coincident usage of specific appliances contributed to an underestimation of the forecast in the three 5-year forecast periods. This was primarily due to the underestimation of the usage of central air conditioners and tertiary (3+) room air conditioning units. This pattern of underestimation had improved by the 2004 forecast for 2009, but it will remain a factor to be watched in future forecasts when the one-year variance analysis is conducted.
Load Factor and Number of Commercial Customers
The peak demand forecast underforecasting bias could have been caused partly by the overforecast of load factor as demonstrated by a pattern of underforecasting overall commercial demand in those years when load factor was over-forecasted. To examine this possibility, forecasting worked in conjunction with the Corporate Accounting Department to analyze the impact of the commercial customer forecast and price as it is used in the econometric model. This model is used to determine the commercial peak demand growth through a conversion using load factor. The years of data used for the analysis were the three year-ahead forecasts for budget years 2005, 2006, and 2007 based on historical model data availability. The analysis showed that the commercial customer forecast did not contribute to the under-forecasting bias for almost all of years.

The finding that the commercial customer forecast did not contribute to the under-forecasting bias in almost all years, demonstrates that the load factor assumption used to convert the final energy forecast to peak demand has a greater impact on the forecasting bias. Therefore, the focus should be on the assumption for load factor. However, the forecast for commercial customers will still be reviewed to see if it plays a role in a forecasting bias going forward.

Price of Electricity
While price of electricity is not forecasted in the model, the variable real price is used in the model. The assumption is that this input will grow at the rate of inflation. Therefore, this input is not considered in the same way as other inputs in the forecast for determining growth and contributing to a forecasting bias.

The Forecasting group has begun to incorporate appropriate changes within the forecasting process based on findings from the review performed for this recommendation. For instance, the growth rate of saturation over the next five years for some appliances (i.e. room air conditioners, computers) has a higher growth rate in the current forecast than the growth rate used in prior forecasts.

In addition, adjustments have been made to the growth in load factor used in the current forecast. Load factor has not been steadily increasing over the last few years, and a higher load factor implies a lower peak demand (and may lead to an under-forecast). Therefore, the current forecast considers this factor more closely by not growing the load factor to the same degree as in prior forecasts.

As part of the evaluation of the factors contributing to the under-estimation bias, it was discovered that there were also factors that were over-forecasted during the same time period. However, these factors, when compared to the factors that were under-forecasted, did not have a significant impact on the peak demand forecast. Going forward, we will continue to review all input factors for adjustments to future forecasts as deemed necessary in either direction.
Some of the changes resulting from this review of input factors contributing to under-forecasting bias were used when developing the 2011 forecast. The Forecasting group will continue to analyze the effect of these input factors, and make appropriate changes to future forecasts based on the results of such analysis.
**Recommendation Number:**  18  
Expand load forecasting activities and capabilities to encompass analysis of uncertainties using sensitivity analyses, probabilistic tools or other applicable techniques. (Conclusion 18)  
Team Lead(s): Joe Oates / John Mucci

**Summary of Implementation Actions:**

This recommendation is complete.

The Demand Forecasting and Revenue and Volume Forecasting groups worked with internal and external subject matter experts to develop three 20-year demand and energy forecast sensitivities that have been used in the development of the Electric Long Range Plan. The sensitivities considered inputs to the demand forecast that would introduce uncertainties to future forecasts; such as the economy, energy policies, demand side management, and new technologies, such as electric vehicle penetration, in the Company’s service area. These forecasts will be used in our analysis of the electric system under different peak demand conditions. CECONY will develop and document sensitivities for long-term peak demand forecasts annually to ensure that a range of possibilities for growth in the peak demand are considered and that factors that are not in existence at the time the forecast is prepared are taken into account. After evaluating a potentially useful software package, we found the tools currently available to the Forecasting groups are adequate for developing such sensitivity analyses. The method used to develop the sensitivities will become a regular approach to the forecasting process, including documentation of the assumptions.

As indicated in the completion summary of recommendation 14, the Company’s forecasting groups eliminated and streamlined tasks and in so doing, freed up the necessary labor resources to implement this recommendation. As a result, there were no additional costs identified at this time to implement the recommendation. By implementing this recommendation, the Company will be doing more “what if” studies of assessing the potential impact of new demand drivers, such as electric vehicles on infrastructure requirements, resulting in more robust planning. The analysis conducted to implement load forecasting recommendations is in-line with our principle to improve continuously and seek ways to refine the demand forecasting process.
Recommendation Number: 19
Develop an improved approach to the documentation, testing, and communication of forecast criteria and assumptions. (Conclusion 19)
Team Lead(s): Joseph Oates / John Mucci

Summary of Implementation Actions:

This recommendation is complete.

Demand Forecasting has developed a template document that lists the primary assumptions used in the long-term electric peak demand forecast. The template includes the major assumptions and how they compare to the prior year’s assumptions. In addition, the template includes a description and a flowchart that show the process of developing the long-term forecast based on the major components.

Revenue and Volume Forecasting has also developed a template that explains the volume forecasting process and the basis for the primary assumptions used in the annual budget. The template includes flowcharts of the overall revenue and volume forecasting process, the econometric modeling process and the assumptions used to produce the volume and revenue forecasts.

Demand Forecasting and Revenue and Volume Forecasting have included a comparison in their templates of the forecast assumptions used in the current year and for the prior year. Annually, both forecasting groups review and test their forecasting models to determine the impact of changed inputs on their forecasts. Demand Forecasting and Revenue and Volume Forecasting will use the template documents to inform the various users of their forecasts of the primary assumptions used in the forecasts and of any changes in the assumptions from the prior year’s forecast. This approach will help users to better understand the drivers of growth and to facilitate an improved understanding of the various forecasts.

Both forecasting groups will continue to discuss the key assumptions used to develop the peak demand, volume and revenue forecasts with upper management.

While the cost to produce these documents was minimal, the benefit of having the documents is to provide greater awareness of the assumptions and drivers that both forecasting groups use to produce their respective forecasts. It will prove beneficial to have this information in one source that is available within the Company. It will also ensure consistency when questions are posed about the forecasts since everyone will be able to reference the same information.
Recommendation Number:  20
Examine and implement as appropriate the efficiencies and quality improvements that might result from utilization of CECONY’s load research program, modified as cost-effective, to support load forecasting. (Conclusion 26)
Team Lead(s):  Joseph Oates / John Mucci

Summary of Implementation Actions:

This recommendation is complete.

After benchmarking with other utilities and examining internal data sources, the Company concluded that the utilization of CECONY’s load research program may enhance our analysis of CECONY summer experience, but is not feasible to be used as a direct input in demand forecasting.

The most recent dataset representing load research data was acquired from the Rate Engineering department and represents 2007 data. The 15 minute interval data collected over a calendar year through meter recorders may contain missing data, zero usage, spikes or valleys caused by voltage problems, irregular usage, and other anomalies. The Rate Engineering Department employs a sophisticated industry-standard process known as VEE (Validation, editing, and estimation) on raw load research data to address these anomalies. The VEE, designed to withstand rate case scrutiny, is performed in preparation of class demand studies for rate case submissions and used in the preparation of class load shapes. Raw data, which is not validated, is available for years other than 2007.

Account data that is not part of the validation process within the Rate Engineering Department can be used to enhance the summer analysis with an independent model using actual daily demand and temperature data for two or more summer seasons.

For example, as part of the 2010 post summer analysis, we extracted Time of Day Large accounts (TODL) commercial demand data to enhance our summer analysis in terms of the commercial segment to determine if the demand in this sector increased or decreased from the prior year. TODL accounts are essentially 100% sampled so that nearly all of TODL accounts for both seasons can be leveraged for the analysis. Using two summer seasons for 2009 and 2010, we performed a weather adjustment process similar to the method used in our annual summer experience analysis for the CECONY system. Using pooled regression, we performed a year-over-year analysis for this customer subset. Although the validation process was not applied to this subset of accounts for these years, the result was still useful for the weather-adjustment analysis since it reinforces the severity and direction of the trend observed on the system level analysis. This TODL model is completely independent of the demand forecasting methodology used for CECONY and provides historical information about growth within this sector. However, the TODL model does not provide any information about the cause of an increase or decrease in the demand data, and therefore,
using it as an input to the forecast is not feasible. The same limitation exists for residential load research data. For example, if our summer experience analysis shows that the CECONY weather-adjusted demand decreased over prior season, this analysis would allow us to understand the extent large commercial customers contributed to that decline. Therefore, the Company envisions using that residential data in a similar fashion as the commercial data, which is to enhance our summer analysis by analyzing year-over-year growth of the customer class.

The utilization of CECONY’s existing load research program will provide benefit by enhancing our summer analysis. Large commercial accounts as well as the aggregated demand from the rest of the accounts will be reviewed as a system analysis using the available load research data. The benefit of using this process to analyze growth trends of customer classes is as stated above with the TODL customer example, which is to assess the growth achieved from the prior year, which would be beneficial for the forecast variance analysis and weather-adjustment analysis of the system demand.

The cost to perform the research and benchmarking associated with this recommendation was approximately $10,000. There are no additional costs to the Company to perform the ongoing analysis. The benefits are as stated above, which is the enhancement to the summer analysis to assess year-over-year growth within the residential sector.
**Recommendation Number: 23**
Establish a structured approach to the consideration of long-term eventualities that might significantly impact load forecasts, such as changes in trends, new technologies and new policies. (Conclusion 30)
Team Lead(s): Joseph Oates / John Mucci

**Summary of Implementation Actions:**

This recommendation is complete.

Benchmarking was performed with other utilities to obtain information on their forecasting methodologies, inputs, assumptions, and models. The benchmarking has been successful in allowing the Company to see how others are forecasting their peak demand and sales in order to make potential improvements/changes to the current processes. There were some findings from the benchmarking that were a common thread between more than one company that participated in the benchmarking. One finding is that many companies develop their sales forecast first and then derive the peak demand forecast from the sales forecast. This method presumes a constant relationship between peak demand and sales over time, which may be a reasonable assumption for forecasting peak demand over a shorter period than what CECONY requires. The companies using this method do not forecast beyond five years ahead or need to forecast down to a network level, in contrast to CECONY’s requirements.

The trend for most of the companies was to develop scenarios or sensitivities, mostly around the Economy, Demand Side Management (DSM), Plug-In Electric Hybrid Vehicles, Appliance Efficiency, and Compact Fluorescent Lighting. As discussed below, the Company has incorporated these factors into the Electric Long Range Plan (ELRP) forecasts and will add other forecast uncertainties where appropriate by determining what other unknowns could potentially affect peak demand in the long-term and should be included in the forecast or forecast sensitivities.

The Demand Forecasting and Revenue and Volume Forecasting groups worked with both internal and external subject matter experts to develop three 20 year electricity demand forecasts that have been used in the development of the ELRP. The sensitivities include the impact of economic assumptions, energy policies, demand side management, and new technologies, such as electric vehicle penetration, in the Company’s service area. These forecasts will be used in our analysis of the electric system under different peak demand conditions. CECONY will develop and document sensitivities for long-term peak demand forecasts annually to ensure that a range of possibilities for growth in the peak demand are considered and that take into account factors that are not in existence at the time the forecast is prepared.
Using demand sensitivities results in a robust planning process and improved capital budgeting – the benefit of this could be significant since our capital budget was $1.8 billion in 2009.

The results of our benchmarking surveys conducted with other comparable utilities, and a brief description of the three forecast sensitivities have been shared with the PSC as part of the completion process.
Recommendation Number:  79
Consolidate duplicative Energy Management operations in the electric and gas hedging functions. (Conclusion 2)
Team Lead(s):  Joseph Oates

Summary of Implementation Actions:

This recommendation is complete.

The departments have or are in the process of implementing a number of actions to better align the electric and gas hedging functions in order to improve performance and effectiveness of the hedging programs. These include:

- **Strategy development** – Included a similar strategy for option purchases in both plans. The analytical results from one group’s efforts were utilized by both groups, avoiding a duplication of effort, or a different analytical approach.
- **Hedge plan development and execution** – Aligned procurement schedules to extent possible within existing constraints. Similar to the prior finding, one group’s observations and optimization efforts were utilized by both groups, avoiding duplication of efforts.
- **Validation of SFAS 161 disclosure data** – Transferred responsibility to Energy Risk Management (also provides for separation of duties). The new process is more effective, since all disclosed data will be reported by the appropriate group in a consistent way.
- **Realignment of hedge portfolios** – Initiated process to transfer Steam Operations gas hedging from gas hedging group to electricity hedging group. Electricity Supply currently hedges the natural gas used by the Company’s non-utility generators (NUGs) contracts. The evaluation and analysis associated with the Company’s Steam Operations generators would be similar to that already performed in Electricity Supply as part of the Electric Hedge Plan. Energy Management would gain efficiency by having the same group perform the hedging analysis for the NUGs and Steam Operations generators.

The results of reviewing the hedging groups’ activities have shown that while some of the specific activities associated with the hedging functions are similar (e.g., adherence to hedging plans and entry of financial transactions into Allegro system of record), a large number of the tasks and knowledge base required to perform electric or gas hedging functions are very different.

Accordingly, the staffing level has remained the same; the staffing change recommendations included in the attached summary document reflect alignment within Energy Management to reflect industry best practices and do not result in direct impacts to customer costs. Further, we conclude that any other improvements we achieve as a result
of improved coordination between the two groups would not provide Full-Time Equivalent (FTE) benefits, but rather improvements in our analysis or implementation of the hedging plans, the benefits from which automatically accrue to the customers under the existing pass-through mechanisms. Therefore, to the extent that ongoing meetings and subsequent implementation of coordination improvements between the two groups result in hedging benefits or improved performance, those benefits will be directly passed on to customers.

**Supplemental Completion Update**

During our 2011 Hedge Plan development process, we implemented changes to the gas hedging approach following our own assessment and input from PSC Gas Staff. The plan is now based on more specific PSC Gas Staff guidance related to the Order to manage price volatility, reducing the amount of hedging needed for gas customers. When we assessed the needs of the hedging group in light of other organizational changes, our existing knowledge base, and cross-training opportunities, we were able to combine the Gas and Electricity hedging groups under one manager.

In May 2011, three of the four Gas Hedging & Market Analysis (GHMA) analysts were transferred to the combined Electricity & Gas Hedging group. The transfer of analytical functions and knowledge within Gas Supply allows us to further benefit from applying knowledge in quantitative techniques in future plans in support of the Company’s long range planning activities, as well as in hedge plan development, without the need to add personnel. It is expected that the new combined group will further align the hedging activities of electric and gas to allow improved analysis and cross-functional coordination.
Recommendation Numbers: 80 and 82

80: Develop a comprehensive portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans.  
(Conclusions 3, 7, 14)

82: Identify, analyze and document all reasonable alternatives to its existing sources for both capacity and energy. Alternatives that are superior to the status quo electric resources should be implemented.  
(Conclusions 8, 9, 11)

Team Lead(s): Joseph Oates

Summary of Implementation Actions:

This recommendation is complete.

The Management Audit report recommended that the Company develop a comprehensive portfolio design and optimized plan for the electric resources required to serve its full-service customers over the long term. A portfolio plan provides a long-term roadmap to determine where the Company’s electric procurement is going regarding resource requirements and future alternatives for effectively meeting them.

The newly developed 2010 Long Term Electricity Supply Plan addresses both recommendations 80 and 82. This 10-year electricity portfolio management plan looks beyond the period of the Three Year Electric Hedge Plan and leverages the work that Energy Management did for the 20-year Electric Long Range Plan (ELRP), including its supply and energy outlook. The 2010 Long Term Electricity Supply Plan focuses on physical supply requirements, including varying levels of customer demand, retail choice, and contracted supply; analysis of alternatives to existing sources of capacity and energy; and initiatives to address the impact to our full-service customers’ costs.

Plan Development

Before developing the electricity portfolio management plan, we reviewed our current goals and objectives for the use of physical electricity resources and the Company’s hedging strategy, which is annually presented and reviewed by Department of Public Service Staff. The hedging strategy incorporates the current physical supply portfolio and various financial products to provide customers with energy at prices reflective of the long-term trend in energy prices, while mitigating short-term price volatility. This hedge plan uses financial instruments to hedge the variability in costs for both market and non-utility generator (NUG) contracted energy costs. The result of the review identified three main goals and objectives for the 2010 Long Term Electricity Supply Plan:

1) Manage supplies effectively to meet customer demand
2) Maintain adequate diversity of supply source mix and pricing structures; and
3) Examine alternatives to mitigate electricity supply costs.
In conjunction with the long-term electricity supply plan development, Energy Management used the three scenarios (Plan Case, Low Case and High Case) that were used to develop the Electric System Long Range Plan. Energy Management developed demand forecasts for these scenarios, which take into consideration such factors as the economy, energy and demand growth and the successful adoption of energy efficiency programs. In our analyses for each scenario, we evaluated and projected the resource mix, electricity price outlook, and customer bill impacts associated with Regional Greenhouse Gas Initiative (RGGI) /CO₂ costs and Renewable Portfolio Standards (RPS), including transmission, over the 20-year planning horizon.

Building on these efforts, we developed and documented our long-term electricity portfolio management plan.

The plan identified a number of important points with respect to the electricity supply portfolio, including:

- The price of natural gas is expected to continue to be the primary driver of customer supply costs.
- Existing supply sources in the energy market are adequate for meeting full service customer requirements.
- We need to carefully monitor retail choice migration to prevent an oversupply situation.
- At this time, we have identified no need for additional capacity resource alternatives. However, the plan recognizes that there are opportunities to be more aggressive with examining capacity resources and commits to pursuing future alternative capacity supply arrangements (e.g., bilateral capacity purchases, RFP schedules for capacity supply, and/or possible financial transactions), where appropriate.

With the development of this plan, we have created a template that we can update and review annually. We will continue to monitor the progress of this plan by evaluating market changes and changes to full-service customer demand requirements. For existing contract options, Energy Management evaluates the benefits to customers with respect to its annual purchase decisions.

For the existing NUG contracts, Energy Management leverages the flexibility within these contracts to produce the most economical result for customers via dispatch optionality and then fills in the remaining customer requirements through purchases from the market (i.e., NYISO). However, we have limited flexibility in restructuring or buying them out. With the advent of the FIN-46 accounting regulations, the implications of restructuring a long-term NUG contract to utility balance sheets and financing costs would be significant.¹

¹ In essence, the utility’s financial statements could be impacted by creating a liability, but without the commensurate ownership of the asset. The utility would also be responsible for certifying effectiveness of the generator’s internal controls which could impact Sarbanes-Oxley compliance and increase financial reporting risk.
The buyout of NUG contracts presents a different set of issues without a clear benefit to customers. These contracts are structured with fixed and variable portions, originally intended to cover the financing and variable costs associated with the projects. Because the structure of these contracts aligns the NUG variable costs with the market costs, there would be no customer benefit through buyout of the contracts. Our analysis shows that the value of these contracts lies in the fixed payments and that the NUG owners would only accept the full present value of the fixed payments in order to close out the contract.

Annually, we will continue to evaluate our long-term contracts, capacity procurement options for strategic implementation, and any opportunities to mitigate customer electricity supply costs. We also recognize that legislation and regulation are also significant drivers of supply cost increases and can change at any time. Thus, we will continue to be active participants in monitoring energy policy impacts to customers and take steps to mitigate costs whenever possible. Furthermore, Energy Management will continue to provide input to the Electric Long Range Plan as signposts change and the plan is updated.

In line with the plan, Electricity Supply will continue to:

- Manage the existing optionality associated with the NUG supply contracts for spot market physical purchase decisions,
- Manage the daily purchase decisions associated with the scheduling of load and NYISO market purchases in the day-ahead and real-time markets,
- Manage the capacity purchases in the NYISO-administered strip, monthly and spot capacity markets to complement our existing supply portfolio, and
- Monitor New York City demand versus supply sources and the impact of other market developments (e.g., capacity additions, energy efficiency and demand response initiatives, the demand curve reset) to seek opportunities to mitigate the cost of capacity supply.

Implementation costs will be minimal as this is part of the responsibilities of the Energy Management group.

One benefit of this long-term plan is that we have created a standard format and template for annual review and update. This will provide a means of more robust evaluation of the electricity supply outlook and forecasts, and can be used to develop plans for the Company’s electric system for different future demand and supply conditions. Additional benefits include energy cost savings that could occur if the Company identifies improvements in its energy supply operations. To the extent that there are savings from our strategic purchase decisions, those savings will be directly passed on to customers as they occur.
Team 7 – Gas Main Replacement  
Executive Sponsor: Claude Trahan

Recommendation Number: 35  
Maintain current information about CECONY’s leak-prone pipe.  
Team Lead(s):  Frank Ciminiello

Summary of Implementation Actions:

This recommendation is complete.

In April 2009, Gas Engineering retained the services of ZEI, an independent outside consultant, to conduct an investigative study to:

- Evaluate the existing and future condition of our gas mains
- Determine the most cost-effective level of main replacement to ensure consistent system improvement
- Evaluate the Company’s cast iron and unprotected steel gas distribution main system and develop the required annual maintenance resulting from various annual main replacement levels

ZEI used the following CECONY information in their analysis:

- Past studies of the cast iron and unprotected bare steel gas distribution systems
- Data relating to repair history of the cast iron and unprotected bare steel (e.g. breaks, repairs, age, location)
- Available soil data (refer to ZEI’s 1988 Steel Main Study)
- Cast iron and unprotected bare steel distribution system by quantities, size, age and location
- System maps
- Repair versus replacement economics
- Cast iron and unprotected bare steel maintenance practices and procedures
- Main Replacement Program (MRP) information
- Cast iron pipe samples removed from the various operating areas

ZEI used two separate approaches to evaluate the future performance of Con Edison’s cast iron and unprotected bare steel main:

1. Statistical Analysis – utilizes leak repair data over a six-year period
2. Rational Analysis – utilizes engineering principles and theoretical models to analyze the effects of factors, which include:
   a. Pipe size
   b. Condition
c. Soil type  
d. Effect of frost  
e. Vehicular and other loads

Based on the two separate yet complementary approaches, which give greater confidence in the results of the study, ZEI provided estimates for the life expectancy of our existing infrastructure. Both approaches confirmed these results. These estimates were used to develop various replacement schedules and identify the most cost-effective replacement strategy. ZEI provided replacement schedules identifying the future repairs of steel corrosion leak repairs, and cast iron joint leak repairs and cracks/breaks. In Section 11 of the enclosed ZEI report entitled, “Replacement Program,” ZEI provided replacement schedules ranging from “no annual replacement” to “60 miles annually” in increments of 10 miles. ZEI identified the impact of these schedules on future corrosion leak repairs, joint leak repairs and cracks/breaks. Based on the replacement schedule and estimated future repair rate, ZEI was able to identify the most cost-effective replacement schedule, or the point of diminishing returns on our replacement investment. The most cost-effective replacement rate for bare steel is 20 miles per year. The most cost-effective replacement program for cast iron differs if the goal is to reduce joint leaks or to reduce breaks/cracks. If the optimization strategy for cast iron main replacement is to reduce joint leaks, then the most cost-effective replacement rate is 20 miles per year. If the optimization strategy for cast iron main replacement is to reduce cracks/breaks, then the most cost-effective replacement rate is 30 miles per year. The 20 miles of steel and 30 miles of cast iron replacement is the rate ultimately used.

While ZEI identified the most cost-effective replacement rates, ZEI also recognizes that there is a significant cost impact that CECONY must take into consideration. Therefore, ZEI recommends that CECONY define the desired end-state and periodically re-evaluate leak repair trends. In order to minimize rate impact to customers while still improving the gas system, CECONY recommended a replacement rate of 35 miles/year (20 miles of cast iron and 15 miles of steel). The 35 miles is based on the fact that 20 miles of cast iron and the 10 miles of steel will yield improvement over the 25 years and as a minimum we determined that we need to replace 5 miles of main with couplings.

Therefore, in conjunction with the ZEI evaluation, Gas Engineering conducted a benchmarking study to identify the inventory, incoming leaks to inventory rate, and annual rate of cast iron and steel replacements for gas utilities within and outside of New York State (NYS). Below is a summary of the benchmarking results:

- While Con Edison has shown a downward trend in gas leaks discovered and leaks per mile, the Company still has the highest leaks per mile rate of any NYS gas utility
- In NYS, Con Edison has the greatest percentage of cast iron and unprotected steel pipe inventory (approximately 63% compared to the next highest, which is National Grid NY at 54%)
- On a national level, our replacement strategy is relatively in line with companies that have a comparable pipe inventory
• Some other countries have already replaced or have active programs to address small diameter cast iron mains. Italy and United Kingdom currently have a much more aggressive cast iron replacement program than Con Edison because of the severity of their problems and mandates to make the replacements.

Gas Engineering reviewed the replacement schedules and the most cost-effective replacement rate provided by ZEI and the benchmarking results. Gas Engineering also evaluated the capital and O&M budget costs and the revenue requirement for each replacement strategy. A meeting was held with PSC Staff to present the results of the ZEI evaluation, benchmarking results and the cost-benefit comparison for the various replacement schedules.

In an effort to minimize the cost impact to customers while providing a strategy to address the most hazardous types of leaks for main replacement (high pressure steel main and coupling leaks and cast iron breaks), the Company recommended to Staff 35 miles of targeted main for replacement annually. Reducing from 40 miles to 35 miles would save the customers an estimated average of $1.7 million annually. In the 2008-2010 rate case, Staff requested the replacement of a minimum of 40 miles of main. Since ZEI identified the optimal level to be 50 miles of replacement, in the 2011-2013 rate case, the joint proposal was negotiated to increase the main replacement performance target from 40 miles to 50 miles annually which includes up to 10 miles of replacement due to interference related main work. This 50 mile target should enable the Company to reduce the steel leaks by half, and the cast iron leaks by two-thirds, by the year 2035.

A cost-benefit and risk analysis was conducted for the replacement rates of 35, 40, and 50 miles of main per year. While those replacement strategies do not show a positive cost-benefit based on reduced operating expenses, the primary benefit of main replacement is the reduction in the risk of serious incidents caused by leaks. Therefore, the value of safety provides a positive cost/benefit. Public and employee safety is paramount to the way we manage and operate our gas system.
**Team 8 – Gas Capacity Planning**  
Executive Sponsors: Luther Tai and Claude Trahan

Recommendations: 15, 86 and 87

**Recommendation Number: 15**  
Find a better way to forecast growth in the peak gas load. (Conclusion 8)  
Team Lead(s): Joseph Oates

**Summary of Implementation Actions:**

This recommendation is complete.

Currently, the firm gas peak demand forecast begins by evaluating the prior winter and adjusting the demand to the design weather temperature variable condition. Once the base peak demand is established, the incremental growth is determined from the natural gas budget forecast developed in the Revenue and Volume section of Corporate Accounting. The incremental growth is then applied to the weather-adjusted base peak demand to develop the final long-term annual forecast.

Demand Forecasting has developed a new approach to forecast the CECONY long-term annual firm gas peak demand over a 10-year period. The primary difference between this new approach and the current approach will be the independent development of the natural gas peak demand forecast by Demand Forecasting. We believe that a more independent process that does not rely exclusively on the gas volume forecast will improve the accuracy of the peak demand forecast by shifting the focus more specifically to the drivers that affect firm natural gas peak demand instead of converting an energy forecast from Revenue and Volume Forecasting to peak demand.

To produce forecasts of firm gas peak demand growth, Demand Forecasting will utilize an approach that combines econometric and end-use models. The econometric model uses historical monthly and quarterly data to explain changes in peak demand. Primary inputs to the econometric model include the price of natural gas and personal income, which are key variables in microeconomic decisions of firm gas demand. In addition, the model will also consider inputs such as population, private non-manufacturing employment, U.S. GDP, wind speed and temperature, with base case forecasts of the economic variables provided by Moody’s Economy.com. In the model, elasticity coefficients establishing the relation between each input variable to peak demand are derived using the historical data, and in turn, these elasticity coefficients will be used to estimate the future impact of the input variables on peak demand.

In addition to the econometrics models, Demand Forecasting analyzes information on the potential for large new customers to be added and for customers that are moving from interruptible to firm gas service. The appropriate incremental demand is considered when
finalizing the peak demand forecast from the model as this incremental demand would not have been captured by the econometric model. The impacts of these variables will be incorporated with the results from the econometric model.

The new demand forecasting framework also considers energy conservation that pertains to space heating (furnace) and water heating. Natural gas consumption is strongly influenced by improvements in overall efficiency as more efficient gas units replace older less efficient models in order to capture natural conservation from units that have reached their lifespan. Increasing natural gas commodity costs may also trigger some consumers to purchase more efficient energy consuming appliances and replace less efficient ones prior to the natural lifespan of the equipment being reached. Furthermore, the framework also accounts for effects of self-generation and demand for alternative fuel natural gas vehicles as these are expected to increase in the foreseeable future.

Using this approach going forward will require more time and effort on the part of the current staff within Energy Management that is estimated to be ½ Full-Time Equivalent (FTE) employee, or approximately $50,000, to produce the long-term firm gas demand forecast. The forecast will no longer be derived from the energy forecast, and the new methodology will require increased information as inputs to the forecast and the model to be developed each year. To offset the resources needed to support forecast development, automation and streamlining of some functions within Demand Forecasting is expected to yield ½ FTE of savings. Hence, no incremental resource is needed to support this effort.

A primary benefit of this new forecasting methodology will be the independent development of the natural gas peak demand forecast by Demand Forecasting and the energy forecast by the Revenue and Volume Forecasting group. This more independent process with its “checks and balances” may improve the accuracy of the peak demand forecast by shifting the focus more specifically to the drivers that affect firm natural gas peak demand instead of converting an energy forecast from Revenue and Volume Forecasting to peak demand. Should the new methodology result in consistently greater accuracy of the long-term firm peak demand forecast, the long-term capital budget can be more closely aligned with future peak demand needs such as pipeline expansion. With the new independent process in place, the two departments will still continue to discuss their forecasts as a means to verify the reasonableness of the forecasted growth.
Recommendation Number: 86
Provide for more regular examination of Gas Supply’s award of supply contracts by Internal Auditing. (Conclusions 7, 8)
Team Lead(s): Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

The 2010 Audit Plan approved by the Board contains the broad and comprehensive program of internal audits to ensure compliance with internal controls governing the operations of Con Edison. The 2010 Audit Plan allocates 3,400 hours to Energy Management related functions. In 2009, the Plan allocated 2,650 hours.

The hours were allocated as follows:

- 1,000 hours have been added to the 2010 audit plan to conduct regular audits of functions related to Electricity Procurement (500 hours) and Gas Procurement (500 hours). The audits will include reviews of compliance with corporate policies and procedures associated with procurement decisions and the documentation required for entering into electric supply contracts.

- In addition, the Company conducts annual SOX controls audits as part of its SOX Controls Testing Plan required under Section 404 of the Sarbanes-Oxley Act (SOX) of 2002. In 2010 we will be testing 55 controls and have allocated 900 man-hours of audit time related to Electricity and Gas Procurement. These controls will be in the broad areas of accounting, hedge accounting, confirmations, credit risk, deal authorization and capture, fuel procurement and inventory, gas supply and purchased power, portfolio valuation and reporting and risk management. A detailed listing of these controls can be seen in the attached SOX controls catalogue. In 2009 we tested the same 55 SOX controls related to energy procurement and also utilized 900 audit hours. The Energy Management SOX controls catalog contains 156 controls. For those controls that are not tested annually in SOX, the Company has devised a rotational controls testing plan which subjects these controls to tests over a seven-year period. In 2010, 13 controls (400 hours) relating to Energy Management-Hedge Accounting will be tested under this plan. In 2009, 29 controls (600 hours) were tested which dealt with gas supply and purchased power, risk management, and portfolio valuation and reporting. As these additional SOX controls are tested on a rotational basis by functional area, the number of controls and hours allocated can fluctuate from year to year.

At CECONY, in 2008 we spent $1.5 billion for the procurement of natural gas for resale. By increasing the amount of review of these procurements in the annual plan we increase the...
ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place. In 2010, we are incorporating this recommendation into our audit plan to further reduce the risk of overpayment or misappropriation of resources, and promote compliance with controls and procedures as a result of the audits.
**Recommendation Number: 87**
Explore applying probability-of-occurrence analysis to its supply-capacity planning.  
(Conclusion 13)
Team Lead(s): Joe Oates

**Summary of Implementation Actions:**

This recommendation is complete.

After examining gas industry and internal data sources, the Company concluded that the application of probability-of-occurrence analysis to natural gas supply and capacity planning is not currently feasible. In addition, our review concludes that the Company has been utilizing an approach – paying an option fee and a price for the commodity supply for winter city-gate purchases (city-gate delivered services/peaking supplies) – that incorporates best practice characteristics that Liberty recommends.

**Background**
As one of its findings, Liberty Consulting Group recommended that the Company explore applying probability-of-occurrence analysis to gas supply capacity planning that others have found useful. Liberty learned about the probabilistic approach used by the New York State Reliability Council (Reliability Council) and the New York Independent System Operator (NYISO) through one of the probabilistic inputs to the collaborative reliability model. This particular input is a probabilistic calculation of the electricity Load Forecast Uncertainty (ELFU), which Con Edison uses to determine the New York City ELFU for the Reliability Council.

Based on the experience with the bulk power system, application of this approach to natural gas capacity planning would address low-probability weather events with non-traditional capacity alternatives, such as purchases of gas supply from customers who agree to sell their supplies to the Company under specified conditions, and options on city-gate purchases.

To address this recommendation, Con Edison set up a multi-disciplinary team with representation from the Gas Supply, Resource Planning, Gas Transmission Engineering, and Gas Control departments. The team examined three areas: application of the Electric Load Forecast Uncertainty model to natural gas, the reliability of supplies to the gas system, and the Company’s non-traditional alternative purchases.

**Application of the Electric Load Forecast Uncertainty Model to Natural Gas**
The Electric Load Forecast Uncertainty (ELFU) is a probabilistic model representing the potential peak demand due to random weather fluctuation. The primary objective of the ELFU is reliability modeling of the New York Control Area. The ELFU methodology represents one of the inputs used by the Reliability Council and the NYISO in reliability studies although it is not used for planning purposes for the CECONY electric transmission and distribution systems.
Theoretically, the model produces an ensemble of possible demand outcomes associated with peak-eliciting temperature variable (TV) and corresponding probability estimates. This approach incorporates both a longer term historic view of peak-eliciting temperatures as well as a recent view of daily demand.

After a thorough analysis of historical natural gas data for CECONY, the Company determined that it is not suitable to use an LFU model for natural gas supply capacity planning. The key points considered in support of this conclusion include:

a. Because our history of daily firm gas customer demand data is limited to year 2000 to the present, correlation of annual peak demand with weather would not be as robust as desired, which is necessary to quantify the level of uncertainty in the peak demand forecast due to weather;
b. A lack of historical observed weather events at around peak demand conditions does not allow for validation of the LFU model against actual experience;
c. The LFU model cannot be used to determine a design condition for capacity planning, since it addresses only the uncertainty of peak demand due to weather and not the uncertainty in supply due to unavailability of interstate pipeline deliveries to the Con Edison system and the unavailability of our natural gas delivery system.

Reliability of Supply to the Gas System
There are significant differences between the natural gas and electric capacity planning, with respect to probability-of-occurrence analysis. These differences include:

a. The consequences of a natural gas outage are greater than the consequences of an electricity outage (e.g., each customer must be individually restored via access to the customer’s dwelling, the potential for damage to customer equipment and piping, and the potential public health impacts of lack of heating during cold weather);
b. The natural gas industry does not have entities that are analogous to the NYISO and Reliability Council to perform planning functions;
c. Interstate pipeline companies design their systems based on total customer contract quantities and by Federal Energy Regulatory Commission policy and do not include reliability contingency capacity in their system design;
d. Natural gas distribution companies each perform capacity and distribution system reliability planning independently and do not have an industry reliability standard, analogous to electric’s loss of energy standard;
e. Reliability data collection for the natural gas industry is not standardized and reported across the interstate pipeline industry, like in the electric industry;
f. Unlike the electric industry, there is limited data regarding natural gas reliability events and their correlation to impact on customers

The team concluded that given the extent of differences, application of a probabilistic approach methodology to the natural gas system is not currently feasible.
Use of Non-traditional Purchases
The Company also reviewed its use of non-traditional purchases for the winters of 2005/2006 through 2009/2010 to determine whether its use of an option to make city-gate purchases is consistent with the approach recommended by Liberty. Con Edison uses an RFP process that identifies the required level of peaking capacity with pricing structures that include an option price (right to call upon gas) and the price of commodity supply (when taken). This approach incorporates characteristics that Liberty recommends as a best practice.

In terms of resources, the team studied the topics addressed in this audit recommendation for approximately eight months. As a result of this study for natural gas, the Company gained valuable insight into the natural gas data analysis used in forecasting demand and gas supply risks. We examined our existing assumptions, data definitions, explored new techniques and ideas, which will improve overall processes.
Team 9 – Performance and Resource Management
Executive Sponsor: Luther Tai

Recommendations: 11, 12, 13, 53, 54, 55, 57, 58, 59, 60, 61, 63, 64, 66, and 81

Recommendation Numbers: 11 and 12
11: Increase the amount of stretch and put more pay at risk as part of a broad revamping of incentive comp.

12: Before the study is done and implemented, reduce the emphasis on O&M expense and increase the weighting for capital expenditure performance and the operating performance measures. (Conclusions 7 and 8)
Team Lead(s): Mary Adamo / Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

For Recommendation 11, we have increased the amount of stretch by introducing cost management measures for both the operating and capital budgets. This is designed to measure how well certain key projects and programs are managed with respect to cost and schedule. Additionally, we have reviewed and increased the stretch associated with various key performance indicators, expanded the corporate operating performance indicators from 12 to 14, and require achievement of seven out of eight measures instead of six out of eight measures to meet the Safety, Environmental, and Employee Development indices. Although we agree with the recommendation to put more pay at risk and survey results indicate that our variable pay is low (six percent of base salary vs. 12 percent industry practice), given the current economic environment, we don’t think now is the appropriate time to implement this provision. Regarding Recommendation 12, we have reduced the emphasis on O&M, added capital expenditures and increased the weighting for operating performance measures.

The Company’s intent is to align employee pay and performance with the interests of our customers and shareholders to promote business sustainability. The Company’s philosophy is to align compensation with company performance and to provide compensation that is competitive to attract and retain talent.

Competitive compensation for officers is determined by using benchmark data from a peer group comprised of 20 peer companies of similar size and scope. The Management Development and Compensation (MD&C) Committee of Con Edison’s Board of Directors seeks to provide base salary, annual incentive, and long-term incentive awards for officers that are competitive with the median levels of compensation provided by the Company’s peer group. Mercer, the MD&C Committee’s consultant, performed an assessment of
executive compensation and concluded that each element of compensation is set at median levels of the peer group, which is conservative for a company based in the New York metropolitan area market.

The Company’s compensation consultant, Hewitt Associates, conducted a thorough assessment for the management compensation program and concluded that Con Edison’s use of base pay, annual variable pay (Management Variable Pay) and equity grants (restricted stock grants) is reasonable and consistent with market practice. Hewitt concluded that Con Edison’s compensation package for base salary is comparable to the median levels of Hewitt’s national utilities data base and Con Edison’s peer group. However, both variable pay and long-term equity grants fall significantly below median levels, which are conservative for a company based in the New York metropolitan area market.

The first set of changes to the Management Variable Pay (MVP) Plan was implemented for 2010. The weights assigned to the three components used to determine the MVP Award Fund (adjusted CECONY net income, operating budget, and key performance indicators) were changed from 50%, 20%, 30% to 25%, 25%, 50% respectively. The impact of not achieving the target threshold for the adjusted CECONY net income component was also changed. If the adjusted CECONY net income achieved for a plan year is 90% or less of the target, only the adjusted CECONY net income component (25%) of the Award Fund will be eliminated, instead of eliminating the entire Award Fund. On March 12, 2010, we communicated the changes to the MVP Plan to all management employees in a Postmaster.

For 2011, we added a new MVP performance measure for capital expenditures. To place greater emphasis on cost management, we also introduced modifiers to the O&M and Capital budget indicators that are designed to measure how well certain projects and programs within the Capital and O&M budgets are managed in terms of cost and schedule. We also added two new performance indicators (Electric Reliability Performance Measure and Meters Read on Cycle), increasing the total from 12 to 14. In order to achieve the maximum of 120 percent for the Performance Indicator component, 14 out of 14 indicators must be met. Three (Safety, Environmental, and Employee Development) of the 14 performance indicators are indices and each index is comprised of eight performance measures. Beginning in 2011, the Company will need to achieve seven out of the eight measures within each of the Safety, Environmental, and Employee Development indices instead of six out of eight in order for that performance measure to be met.

On January 31, 2011, we communicated the 2011 plan changes to all management employees in a Postmaster. In April 2011, following the approval of the 2011 targets, a Postmaster (dated April 26, 2011) was sent to all management employees with the updated link to the 2011 targets, O&M and Capital modifiers, and the 14 corporate level performance indicators.
In summary, the Management Variable Pay plan works as follows: The Target Fund is equal to the base salary of all eligible employees as of December 31, multiplied by their respective target percentages. The target percentages vary by band as follows:

<table>
<thead>
<tr>
<th>Employee Salary Band</th>
<th>Target Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Band Levels S, EP, 1L/H, 2L/H, and 60 – 62</td>
<td>4.5%</td>
</tr>
<tr>
<td>Band Levels 3L/H, and 63 – 64</td>
<td>10.0%</td>
</tr>
<tr>
<td>Band Levels 4L/H and 65 – 66</td>
<td>15.0%</td>
</tr>
</tbody>
</table>

The size of the Management Variable Pay Fund can vary from 0% to 120% of the Target Fund based on actual performance results achieved. The weights assigned to each component for the performance period beginning January 1, 2011 are as follows:

- Key Performance Indicators (14) 50%
- Operating Budget* 15%
- Capital Budget* 15%
- Adjusted CECONY Net Income 20%

* Results adjusted based on achievement of modifier targets

Implementation costs were minimal as the compensation consulting studies were done as part of the Company’s normal review and assessment of compensation practices.

Con Edison’s current compensation program components, merit pay, variable pay, and restricted stock grant, are typical among utility and other industries. The variable pay and restricted stock grant components of the current management compensation program places at risk a portion of an employee’s compensation which must be re-earned each year through the achievement of pre-determined performance and cost management measures.

The reason for having a competitive program is to have the ability to attract outside talent and for retention of competent employees. Performance targets are aligned with payouts to motivate employees to achieve the desired goals.

Each year, as part of our annual review process, we review performance indicators to evaluate the effectiveness of the plan and make changes as appropriate.
Recommendation Number: 13
Develop a corporate-wide management information system.
Team Lead(s): Nick Colonna / Stephanie Bailey

Summary of Implementation Actions:
This recommendation is complete.

Background
Con Edison utilizes a Corporate Performance Indicator (CPI) dashboard system to visually show status of its Key Performance Indicators (KPIs). Liberty concluded that Con Edison’s existing CPI system and process have provided useful information to the operating areas particularly since the performance measurements have been consistent over recent history, and that managers paid close attention to the CPI system and to their own performance. However, Liberty also indicated that as a tool, the CPI system primarily functioned as a static or “month at a time” viewing system, and it did not have the capability to create and display graphs, trends, cumulative results, or to allow robust analysis.

To address this recommendation, Con Edison enhanced the functionality of its CPI system to provide trending capabilities. These enhancements support and promote the Company’s increased focus on longer-term performance, its use of performance stretch goals, and greater emphasis on cost consciousness and capital expenditure performance, all of which are addressed in detail in Recommendations 11 and 12.

Implementation
A team was formed to identify the scope and type of information to store and trend, and to develop the project plan. The team followed Liberty’s general outline for implementation:
- Research available platforms
- Review systems of a sample of utilities and business enterprises
- Specify the attributes of the system, including analytical capabilities
- Develop and deploy deliverables in a phased approach
- Perform a cost, benefit analysis

Each of these outlined points is described below.

Research Available Platforms
Four alternatives for extending the capabilities of the CPI system were assessed:

1. Purchase and configure an off-the-shelf performance indicator software package
2. Use Business Intelligence (BI) software development tools to extend the functionality of the CPI system
3. Design and implement a fully customized solution
4. Enhance the existing application to provide trending capabilities

<table>
<thead>
<tr>
<th>Option</th>
<th>Description</th>
<th>Benefit</th>
<th>Drawback</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Purchasing and configuring an off-the-shelf performance indicator software package: (e.g. ElegantJ BI or Balanced Scorecard Designer) that offer pre-packaged performance indicators for the Utilities industry, and which can be implemented with little or no customization.</td>
<td>Rapid time-to-implement; reduced risk (on account of known software capabilities and the lack thereof)</td>
<td>Rigid capabilities; would need to replace existing system; vendor dependence</td>
</tr>
<tr>
<td>2</td>
<td>Using Business Intelligence software development tools to extend the functionality of the CPI system: (e.g. Cognos, Microsoft) specifically designed to aid in business intelligence development (e.g. interactive/drill-down reports, dashboards etc.).</td>
<td>Toolsets are designed for BI development; wide range of BI capabilities (self-service reports, interactive dashboards, real-time data integration etc.)</td>
<td>Few pre-packaged capabilities; development and ongoing costs would be significant</td>
</tr>
<tr>
<td>3</td>
<td>Designing and implementing a fully customized solution using standard development tools such as Microsoft VB.net or C#.</td>
<td>In-house skills can be utilized, fully customizable to user requirements</td>
<td>No benefit of any pre-developed components; greater maintenance and support needed</td>
</tr>
<tr>
<td>4</td>
<td>Enhancing existing application to provide trending capabilities: Modify CPI application to provide limited trending capabilities (e.g. view two types of charts: line chart and horizontal bar graph) and the ability to extract historical (trend) data.</td>
<td>Limited changes needed, in-house skills can be utilized</td>
<td>No apparent drawback. Trending feature to be implemented to monitor performance in key areas.</td>
</tr>
</tbody>
</table>

After the team’s initial assessment, Options 2 and 4 above were deemed most suitable for the following reasons:

Option 2 is closer in scope to the requirements of Recommendation 13; however, it requires more time and cost. BI tools provide the right capabilities (which reduce software development complexity/time) and can be customized to Con Edison requirements; however; the current system can be extended, and does not need to be replaced in its entirety. The licensing model is more favorable for Con Edison; however, off-the-shelf packages do not fit the business requirements, and are not available from standard BI vendors. Fully custom development increases software development complexity and time.
Option 4 was determined to be most appropriate when compared to other options. It offers valuable analysis (trending) capabilities for a fraction of the cost. This enhancement to the CPI system, in combination with the BI tools that will be offered for financial reporting as part of the Company’s roll-out of its Enterprise Resource Planning (ERP) system, Project One, will add up to a comprehensive management information system. Therefore, Option 4 was chosen as the better of the two options.

Review Systems of a Sample of Utilities and Business Enterprises
Con Edison’s Information Resources (IR) group evaluated strategies for effectively displaying different kinds of visuals considering the Company’s various commodities, services, and operating environments. Con Edison needed functionality suitable to the diverse nature of the Company. There is no standard software package that can be implemented “out of the box,” and customizing the Company’s performance measures to standard software capabilities would hinder operations in getting the work done.

Presentation of KPI performance through a variety of visuals (charts and graphs) could produce inconsistent and debatable perspectives on performance. Implementation evaluated the various graphics used across other industries, and the team decided a combination of bar and line graphs is the best tool to effectively trend KPI data from different operating areas while providing the users with a consistent user interface and the ability to export CPI data to Microsoft Excel for further data analysis.

Attributes of the System, Including Analytical Capabilities
The team determined that the CPI system should use one site for both information storage and analysis, should be accessible to each department for update and reference on an ongoing basis, and should support “self-service trending.” For the purposes of this effort, trending is defined as the plotting of how a KPI value changes over time.

The “self-service trending” process is completed as follows:

- User selects a KPI for trending
- User selects type of visualization from a pre-defined set of options for visualization, e.g. bar charts, line graphs
- User selects the number of data points, i.e. the number of historical values, to include in the trending visualization.
- The system will enforce validation and constraints, such as the availability of sufficient past data for trending
- In addition, there may be limitations in that not all KPIs may be available for trending. KPI’s that are not quantitative in nature cannot be trended.
Develop and Deploy Deliverables in a Phased Approach

The development of the trending feature for the CPI dashboard was completed by January 2011. Users can now trend any quantitative Key Performance Indicators (KPIs) within the system. The trending feature provides users with the flexibility to trend one or more KPIs at a time and view multiple trend charts. The selection menu provides users access and functionality with all views. Selection from various icons enables the user to easily access descriptions of the indicators and associated performance data and to customize the trend charts. The data can be viewed by month, quarter, half-year or year or by selected start and end dates.

Trend charts along with the associated data with details can be exported to Microsoft Excel for further analysis. This capability enhances the reporting of KPI data and gives users access to trending data that was previously not available from the CPI dashboard system.

The user can utilize KPI performance information to better ascertain current and trended performance of key indicators in a timely manner and assess if any action is required based on the trends provided. The user can generate reports at any time and use the information accordingly.

The development of training documents and aids was completed by January 2011 and is available to all management employees via direct access from the CPI system. Training sessions were provided to over 50 delegates using the system. In addition, a Postmaster was sent to employees describing the new trending feature of the system on March 2, 2011.

Costs and Benefits

The existing system provided useful information to the operating areas, and enhancing the existing application for trending was the most feasible and cost effective of the options considered. The cost of this option was forecasted to be $180,000 as compared to the implementation cost of the next best option, estimated at $1.65 million to use BI tools.

In-house resources were utilized to develop this system enhancement. In-house implementation was projected to provide the shortest time-to-development, and would utilize in-house computer skills and thus, not require additional software licensing costs.

The trending feature was completed ahead of schedule and under budget. The final cost was $82,000, less than the $180,000 projected cost, due to the optimization of resources across multiple projects.

Ongoing savings are also expected. Based on a recent survey of CPI system users, with the previous version of the CPI Dashboard they spent approximately 1,000 hours creating trend and other presentation data. Since these trend charts and associated data tables can now be generated automatically, the time to produce these KPI presentation materials will be
reduced by 50 percent. This equates to efficiency savings of 500 hours per year, or approximately $20,000 in cost savings per year, and results in a payback of four years.

In addition, the system will allow each organization to proactively monitor its cost and performance trends. As discussed above, the trending feature provides users with the flexibility to trend one or more KPIs at a time and view multiple trend charts. Users can also perform comparisons with other similar KPIs using the data extracted from the CPI dashboard. This enables faster reporting of information, thus increasing efficiency in utilizing KPI data. It also allows for greater transparency and provides a venue for more open communication of information.
Recommendation Number: 53
Perform comprehensive resource analysis for all business units on a quarterly or semi-annual basis.
Team Lead(s): Mary Adamo / Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

The Company recognized as part of its Human Resource strategy, the need for a robust workforce planning tool to help managers identify workforce needs in the future, to identify gaps between demand and supply for physical workers, and to develop resource related strategies for improved long-term resource planning. The Company selected the VEMO (Virtual Enterprise Modeling) model, and designated a workforce planning analyst who will manage and develop data reports to be used in the workforce planning process.

Four actions have been taken to address this recommendation. Each milestone activity is summarized below.

1) Examine the full range of capabilities of the VEMO workforce planning model to see if it can meet the requirements identified in the recommendation

A team of Cost Management and Human Resource professionals was assembled to examine the capabilities of VEMO. We learned that VEMO creates a variety of standard workforce planning and human capital measures, which can be delivered as dashboards, scorecards, exportable data grids, and standard reports. In consultation with the VEMO vendor, we developed visual dashboard reports and are developing a planning module for use by Human Resources personnel, Cost Management professionals, and line manager personnel to address workforce planning objectives.

These dashboard reports will address the following components of recommendation 53:

- Understand physical labor supply requirements at various skill levels based on five-year forecasts of work demand, projected attrition and anticipated job market environment.
- Line organizations should be able to plan their resources to meet demands better and overtime levels will be more effectively controlled.
- Analysis on how General Utility Workers (GUWs) will replenish retirees over next 5 to 7 years to help Cost Managers assess how productivity and costs are impacted.

2) Benchmark for best practices in Workforce Planning and how applications are used and determine if the deliverable can be accomplished at no incremental costs as identified in the recommendation
In 2008, we began to investigate the Workforce Planning function for the purposes of establishing this activity in our Human Resources organization. The investigation examined the state of this activity in business, including the workforce planning software systems and methodologies available in the market and in use by other companies.

We were able to benchmark with 13 other utilities on the use of software for Workforce Planning. From the benchmarking, we learned that several organizations are leaders in the provision of workforce planning software systems and methodologies. Subsequently, we met with representatives from Infohrm, Aruspex and VEMO to discuss the workforce planning process and the tools available to carry out the process. Each of these companies had a software tool that we previewed for potential purchase and use in our endeavor. Based on these demonstrations, we concluded that VEMO offered us the best tool for launching our activity. We selected VEMO after checking with companies that had purchased their tool. In 2009, we began to implement the VEMO tool. We do not anticipate any incremental costs to be incurred. We have a paid subscription that runs from June of 2009 to June of 2012.

3) **Determine if the suggested analysis will derive the benefits as described**

The VEMO application has been established in production for review and use by our team. We evaluated the reports that have been established and found multiple benefits that will contribute to the resource planning process. We are listing several of these reports and benefits they provide.

1. **Forecasted Workforce Activity** – The past data will provide planning information for future forecasted workforce activity.

2. **Turnover & Hiring Trend** - Beneficial to organizations in being able to view their attrition over the last several years and the trends associated with it and what that may mean in the future.

3. **Retirement Likelihood Standard** – Useful for organizations in assessing what retirements are likely in the next year and for several years to come.

4. **Age/Service Demographics** – Data on age could be useful in looking at population movement across age groups.

5. **Headcount Trend** – Useful data for an organization to assess their change in headcount over time and compare this to the work that was accomplished.

4) **Establish schedules with operating groups on a semi-annual basis to review their short term and long term resource requirements**

Our plan to do this consists of the following:

1. We decided to conduct resource planning on a semi-annual basis to coincide with the budget planning process. The first time frame would occur between May and July and the second timeframe would be from November to January.
2. Cost Management and Human Resource Professionals will partner in the use of the tool to assist managers in the resource planning process.

3. Workforce Planning Professionals will work with these groups to facilitate this process. This will include training, security access approvals, resource planning discussions, and data support and upgrades to the application.

4. Conduct meetings with these groups to introduce this plan. To date, we have met and introduced this plan to Cost Management and Human Resource Professionals.

5. Workforce Planning Analysts have been assigned to each organization in CECONY to authorize, train and facilitate the resource planning discussions.

The cost to implement this recommendation was $400,000. The $400,000 was composed of $240,000 for the software over the three-year subscription period, a one-time $155,000 for system implementation, and $5,000 related to the evaluation of this recommendation by subject matter experts. For the next three years, we expect savings of $163,000 per year (i.e., $150,000 due to the optimization of skills training and $13,000 due to automated report generation). The total savings over the next three years, $489,000, is greater than the implementation cost of $400,000 and results in a payback of 2.5 years. Beyond the third year, the annual subscription is $80,000 and we expect continued net savings.
**Recommendation Number:** 54  
Assess and monitor the productivity and cost impacts of carrying an extra trainee on some work crews on a continuous basis to achieve more efficient resource management.  
(Conclusion 5)  
Team Lead(s): Mary Adamo

**Summary of Implementation Actions:**

This recommendation is complete.

As new trainees are hired into Electric Operations, they are introduced to the workforce as General Utility Workers (GUWs). GUWs are focused on learning, practicing, and mastering basic and intermediate skills for the job they are working towards. Advancement to titles above this GUW training title is achieved through completion of classroom and on-the-job training and by passing standardized skills assessments.

The Company has hired a greater number of new employees, and therefore GUWs, in recent years. As hiring has increased, so has the requirement for on-the-job training time to support the advancement of skills for this workforce expansion; each of these new employees must spend time in the field learning from experienced crews as they work. Accordingly, carrying an extra trainee on a crew is directly correlated to the hiring of new employees. This added training puts an additional requirement on resources and productivity.

The impact of on-the-job training on resources and productivity varies by organization, due to the training requirements defined for each career path. Skills for different positions vary, as does the amount of on-the-job training time. These training time differences are a function of training timelines defined in individual career paths for GUWs to achieve higher titles. To measure the extent of this impact, Electric Operations has created a specific work code to be used in daily time reporting. Time associated with this work code can be identified and the cost impact on an organization can be calculated.

Knowing the cost of carrying the extra trainee will provide a better understanding of cost variations and the impact on productivity, which will help in making financial decisions in hiring practices. In an effort to ensure consistency throughout Electric Operations and to improve the utility of this analysis in the future, a guideline document with usage clarification for how this type of training time is reported has been established.

To measure this impact, analyses were completed for both O&M and Capital functions for the organization that carries the extra trainee for the longest time: Overhead Construction. These analyses focused on the following key work functions:

- Pole installation
- Maintenance work associated with completion of capital projects
• Installation of aerial cable (pole mounted distribution feeders)
• Service Installations

Our analyses indicated that installing poles had the most trainee time associated, and the unit cost increased $349 per unit (i.e., 3.6% of overall unit cost for pole installation); the total cost for the year was approximately $840,000. This is understandable, as new GUWs cannot work on primary, or secondary, so much of their time is spent learning the intricacies of installing poles. Impact to new service installations was approximately $26 per unit additional, and the total associated cost for the year was approximately $164,000. The O&M activity with the largest cost impact was maintenance associated with capital projects, which is primarily transferring wire, and here the unit cost was impacted $29 per unit on an approximate cost of $870,000 for the year. Installing aerial cable had very little trainee time charged to that function, and so had negligible impact to unit cost.

To mitigate the impact of on-the-job training, the hiring of new GUWs should align with the goal to moderate the impact of training on unit cost and productivity. The Company has a planning process in place to address the requirements for training new employees in the context of work volume forecasts and the concurrent capacity of experienced crewmembers to provide on-the-job training. These planning activities are also coordinated with the Company’s centralized training center.

Using the consistent guideline documentation to assess and monitor the productivity and cost impacts of carrying an extra trainee will enable improved analysis and review by Electric Operations’ planning organizations.
Recommendation Number: 55
Conduct a root cause analysis of the upward trend in OSHA target rate in Gas Operations and prepare and implement a corrective action program
Team Lead(s): Randy Price / Katherine Boden

Summary of Implementation Actions:

This recommendation is complete.

As part of the Company’s implementation of this recommendation, the Gas Operations organization reviewed employee injury data from 2005 through 2009. A review of approximately 200 injuries provided the following significant findings:

- Employees aged 23 to 32 with 0 to 5 years of service were the most frequently injured group
- General Utility Workers (GUWs) made up about 15% of the overall population and accounted for about 40% of the injuries
- Approximately half of the injuries occurred while performing tasks ancillary to the job (i.e. getting in and out of the vehicle, carrying tools, etc.) and about 50% of the injuries occurred while performing a job related task (i.e. tapping, excavating, etc.)
- Strains and sprains accounted for 50% of gas injuries overall
- GUWs and Outplant Mechanic A’s were the two most frequently injured job titles
- Of approximately 1,000 employees in Gas Operations, 21 had repeat recordable injuries, which accounted for 25% of all injuries
- Of approximately 100 sprain/strain recordable injuries, 38 could not be correlated with the task that was being performed.

Based on a root cause analysis, injuries were placed into three main categories; insufficient situational awareness (inattention), ergonomic issues (improper tool use and/or poor body positioning) and insufficient planning. These three contributing factors accounted for approximately 90% of the injuries that occurred over the past five years. Targeted corrective actions in five categories have been identified to address the three main contributing factors. Accountability of employees and management are addressed as part of our overall corrective action plan. The five corrective action categories are:

- Job Planning
- Case Management
- Benchmarking
- Employee Accountability
- Ergonomics
**Job Planning** – Job safety planning is a critical aspect of working safely. The process consists of five elements; identifying the hazards associated with the job, eliminating the hazards whenever practical, controlling the hazards when they can’t be eliminated, protecting yourself and the public against injury, and minimizing the impact should an accident occur. Approximately 45 of the 200 injuries (22%) reviewed involved employees performing the work not considering all aspects of the job safety planning process. We are in the process of implementing Gas-specific simulated training to help employees improve their skills through interactive methods that address both the safety and operational aspects of the job. Through this training, employees will learn the consequences of errors in a learning environment, and improve their job planning skills, while incorporating safety into the job. Initiatives are also in progress to enhance both the job safety planning and job briefing processes. Gas Operations job safety planning forms have been revised to be more user-friendly. Employees are receiving ongoing coaching on job safety planning, and field observations are conducted to ensure that all aspects of the job, including identification of hazards and controls, have been considered before work begins. Employees are encouraged to perform their own job site evaluations and add to the briefing given by the supervisor. This practice is meant to foster a questioning mindset and develop meaningful observations of the job site before proceeding with work, which not only improves the overall planning but also helps to improve situational awareness.

**Case Management** – This strategy includes initiatives to reduce employee lost time associated with injuries, through measures such as following up on employees who are out of work due to injury and aggressive management of injuries at the outset through ongoing consultation and discussion with Occupational Health and Workers’ Compensation. Cases were classified as questionable when the injury was not consistent with the task being performed. Over the five-year review period, 38 cases were questionable. Better management of these cases may have changed the OSHA classification and potentially reduced the days away from work. A case management team consisting of Occupational Health, Workers’ Compensation and Operations now meets monthly to discuss the protocols and concerns and promote awareness for better management of injury cases. Good case management can potentially reduce days away from work associated with injuries, improve supervisor accountability, and build helpful relationships with Workers’ Compensation and Occupational Health.

**Benchmarking** – In an effort to continuously improve our safety performance and keep our safety initiatives fresh and up-to-date, Gas Operations has formed a union/management benchmarking team that is meeting with other gas utilities and non-gas industry leaders to share ideas and identify best practices. We have developed benchmarking criteria and so far have conducted benchmarking with Central Hudson Gas & Electric. During our discussions and field visits we identified two best practices. Central Hudson’s work trucks are ergonomically designed. Tools, first aid materials, wheel chocks and pavement breakers are stored and accessed from the exterior of the truck. This reduces the number of times employees have to enter and exit the vehicle to get tools and equipment and also reduces lifting and carrying both of which have been sources of injury in Gas Operations. We are working with our
Transportation group to see if any of these designs can be implemented at Con Edison. Central Hudson also emphasizes positive reinforcement and recognition of its employees. Pictures of employees and a personal explanation of why they choose to work safely are hung up throughout their work locations. Since our visit, we have produced a video where our mechanics talk about what safety means to them.

**Employee Accountability** – To increase employee accountability, we have implemented daily safety calls, monthly critical incident reviews at General Manager and Strategy meetings, and field visits by all levels of management to speak with and influence employees in their work environment. We have also developed a supervisor scorecard to demonstrate individual contribution to various safety and productivity targets. By measuring individual performance, supervisors can be held accountable for their work and can in turn hold their own employees accountable. In addition, on a biweekly basis General Managers review safety violations, injuries and accidents, and procedural violations and ensure that discipline whenever given, is consistent and timely.

**Ergonomics** – One of the primary root causes of injuries in Gas Operations over the past five years is related to improper body positioning and improper tool usage. These injuries account for approximately 35% of all injuries between 2005 and 2009. Ergonomic injuries produce strains and sprains and our newer workforce (employees with less than 5 years of service) is the primary contributor to this injury class. Strategies to address these injuries must encompass several areas. The physical abilities evaluation for new candidates has to reflect day to day work in Gas Operations. We have learned through focus groups and discussions with both union and management that the current testing needs to be revised to better reflect day to day work. A team will be working on this in the fourth quarter. A team is currently working on a video of gas operations activities that will be shown to prospective new hires to provide them with an accurate visual description of the work performed in Gas Operations. This will let them know in advance the physical intensity of the work. We continue to work with R&D in evaluating new tools to help reduce ergonomic stressors. Currently, a lightweight jackhammer and a two handed pogo stick are being evaluated in the field. A lift assist device has been placed in all operating areas to aid with heavy lifting.

In addition to the initiatives described above, an ongoing commitment from all employees and all levels of management has been vital to this improvement. Communication on the importance of integrating safety into our day to day business is ongoing. A quarterly video is shown to all employees discussing the importance of safety. Also employees are being recognized for good safety performance when they are observed in the field and when significant milestones are achieved. These actions are celebrated to preserve interest and maintain focus. We continue to do in depth investigations of our incidents and identify the root causes of our injuries. Our corrective actions are reviewed regularly to ensure that the actions are still timely and appropriate for the conditions we find.

There were no significant costs associated with the data collection, review and root cause analysis. The benefits of performing the root cause analysis and implementing a corrective
action plan have increased Gas Operations focus on safety and improved worker morale. This improved focus has resulted in a reduction in injuries while improving productivity and potentially reducing costs associated with injuries. Gas Operations continues to work towards achieving top safety performance in the next years. Achieving this level of performance by 2014 would represent an improvement of greater than 50% over Gas Operations’ performance during the previous 5 years.

We have evaluated potential cost savings from a reduction in lost work days, as well as savings associated with medical treatment costs. Over the past five years, Gas Operations averaged 955 lost work days per year. At a current man-hour rate of $100 and an employee working an 8-hour day, these average lost days amount to $764,000 per year in lost productivity.

In addition to the lost productivity when a worker is injured, there are also costs associated with their medical care. The National Safety Council has identified that the average cost of medical treatment per lost work day case injury is $39,600. Based on Gas Operations average of 39 lost work day case injuries per year over the past five years, medical care costs amount to $1.5 million. In total, costs associated with lost productivity and medical care total more than $2.3 million per year for Gas Operations.

As of June 30, 2010, Gas Operations had a total of 161 lost days from 10 lost work day injury cases. For the same period last year, Gas Operations had 721 lost work days from 26 lost work day injury cases. Forecasting this data through the end of this year, we can anticipate a total of 350 lost work days from 21 lost work day injury cases. Using the previously stated five year average medical treatment and care costs of $2.3 million per year, our 2010 savings could approach $1.2 million. If we meet our projected OSHA rate targets yearly through 2014, Gas Operations has the potential to save between approximately $1.2 million and $1.5 million per year for the five year period between 2010 and 2014, in productivity and medical care costs. This totals approximately $6.8 million in savings for the five year period. Cost savings are the result of the more important reduction in the occurrence and duration of employee injuries. The ultimate goal of our strong and continued focus on safety is an injury free Gas Operations workforce.
Recommendation Number: 57
Increase efforts to segregate safety from contractual issues in management/bargaining unit dialogue.
Team Lead(s): Mary Adamo / Rich Bagwell

Summary of Implementation Actions:
This recommendation is complete.

A team of union and management representatives\(^1\) was formed to conduct a benchmarking study to determine what processes CECONY can adopt to improve efforts to segregate safety from contractual issues. This initiative included:

- Identifying and benchmarking other utilities that have demonstrated a consistent and successful history of separating safety concerns from contractual issues.
- Identifying the best practices of those utilities to create a sustainable safety model that CECONY can adopt, where management and union interests come together for an integrated effort at safety.

The union-management team utilized information and results from the external benchmarking. Two utilities were identified as being leaders in separating safety concerns from contractual issues. One of those utilities, Public Service Enterprise Group (PSEG), has a service territory and union work force similar to CECONY. For this utility, 1997 was a pivotal year in terms of safety performance. Change started with a top-down approach to improve their safety record. Union and management leadership drafted a safety commitment letter, which was signed by PSEG executives and union officers. It articulated a mutual commitment to: Trust, Care, Knowledge, and Communication. PSEG implemented a "council structure" to get all levels involved with workplace safety improvement. PSEG’s safety management group cited OSHA incidence rates as an indication of the program’s sustainability since inception.

The second utility, Florida Power & Light Company (FPL), has a similar structure to CECONY and also has a large unionized work force. In 1973, FPL management and union employees made safety a priority, and created a structure and process similar to the one used at PSEG, referred to as the Joint Safety Program. The program has a committee structure with a local, business, and corporate level. At the local level, the union and management committees are very active in dealing with safety concerns and meet twice a month. One of the local union vice presidents indicated that there is a commitment to safety, and regardless of any contractual issues, the committees remain intact and focused on safety concerns.

Based on the benchmarking studies, the CECONY union-management team has drafted a health and safety system proposal that incorporates the features found in the PSEG and FPL models.

\(^1\) While Local 1-2 leadership initially participated in this effort, they withdrew from the union management team. Local 3 leadership remains committed to this effort.
This proposal is called the Health & Safety Ladder. This proposal recommends the implementation of a system whereby local organizations can raise, discuss, and resolve safety and health concerns; identify means and mechanisms to promote employee safety and well-being; and provide an open forum to achieve an accident free workplace.

The Health & Safety Ladder initiative will incorporate local, regional, and corporate safety committees, comprising of both union and management employees. There will be elected chairpersons, by-laws, and oversight by the corporate committee to ensure consistency and to measure effectiveness. A commitment statement will also be created and signed by union and management leadership.

The implementation of the Health & Safety Ladder system will support and work in conjunction with the implementation of recommendation 58, which states that CECONY should review safety targets with the objective of adapting “stretch” but attainable levels that exceed historical averages. The primary driver for improving safety performance is to ensure that our employees work safely and “go home the way they came to work.” It also fosters a company culture that sustains our commitment to safety and health, contributes to injury reduction, and improves employee morale. The Company has established a goal to achieve and maintain 1st quartile performance for its OSHA incidence rate at 1.5 within five years (2014). The Health & Safety Ladder system will help in achieving this goal.

The timetable for implementation of the Health & Safety Ladder system is:

- May 1 to July 30, 2010 – finalize draft Health & Safety Ladder system document, develop and have Local 3 and management leadership sign a commitment statement.
- July 1, 2010 to August 31, 2010 – communication roll out to employees via Town Hall meetings, postmasters, emails, etc. Create local, regional, and corporate committees, establish by-laws, charter, and elect chairpersons.
- December 31, 2010 – evaluate the effectiveness of the system, and make improvements where necessary. Revisit discussions with Local 1-2, sharing progress and results of effort with Local 3.

The Health & Safety Ladder system will be implemented in phases, starting in 2010 with Local 3. The incremental costs have been estimated at approximately $23,000 for 2010.

Phase 2 would begin in 2011 after a review of the results of Phase 1, and will also depend on successful discussions with Local 1-2 and their participation in this program. The costs for this initiative will gradually increase during 2011, as the program gains recognition and more meetings are conducted. The Company expects that by implementing the Health & Safety Ladder system, union/management relationships should improve and there would be some related savings due to the reduction in grievances and arbitrations. For example, the Company spends approximately $4,000 per arbitration case. There are approximately 100 arbitration cases scheduled a year, a 6% reduction in arbitration cases would result in a savings of $24,000.
As stated in the response to Recommendation 58, an improved focus on safety should in turn result in a reduction in injuries, improved worker morale, as well as help to maintain a productive workforce and potentially reduce costs associated with injuries. Also, it is expected that as the Company’s overall safety performance improves, the level of employee injuries will decrease and as such, it is expected that the overall time away from work will decrease as well. The incremental costs associated with implementing this initiative should be minimal. The emphasis will be on refining the elements of the program, eventually leading to reductions in frequency of meetings, as safety concerns and contractual issues are kept separate. This benefit was apparent in the experience at PSEG as their program matured.
**Recommendation Number:** 58

Review safety targets with the objective of adapting “stretch”, but attainable levels that exceed historical averages.

**Team Lead(s):** Randy Price

**Summary of Implementation Actions:**

This recommendation is complete.

Safety is a top priority for the Company. The primary driver for improving safety performance is to ensure that our employees work safely and “go home the way they came to work.” It also fosters a company culture that sustains our commitment to safety and health, contributes to injury reduction, and improves worker morale.

The main performance metric in the area of employee safety is the OSHA incidence rate. Company safety performance was analyzed using various statistical tools, such as statistical process control charts and regression analysis, to look at performance trends and to determine whether statistically significant progress had been made. These tools were also used to forecast likely performance scenarios for 2010. In order to evaluate options for establishing a new target, we looked at available benchmarking data as to how other Transmission & Distribution (T&D) operations of utility companies performed, using the OSHA incidence rate as a metric. The Company’s current safety performance, as measured by this incidence rate, is approximately at the midpoint of its industry peers. The 2008 benchmarking data showed that 1st quartile performance for the OSHA incidence rate of these benchmarked operations is 1.62. The Company has established a goal to achieve and maintain 1st quartile performance for its OSHA incidence rate at 1.5 within five years (2014). With this 5-year goal established, a 2010 target was proposed by evaluating the Company’s 3-year OSHA incidence rate average and developing a straight line reduction toward the 2014 goal. For 2010, the reduction target (2.9 OSHA incidence rate) will represent an approximate reduction of 11% below the three-year average (2007, 2008, and 2009) of 3.26.

By establishing a stretch, but attainable goal to achieve and maintain top-quartile safety performance within the next five years through steadily reduced annual performance targets, we anticipate a greater focus on safety. This improved focus should in turn result in a reduction in injuries, improved worker morale, as well as help to maintain a productive workforce and potentially reduce costs associated with injuries. Achieving this level of performance by 2014 represents an improvement of greater than 50% over the Company’s current performance. An estimated productivity improvement of >9000 days (or equivalently >38 Full Time Employees, FTEs) annually could be achieved when the Company reaches this level of performance. This estimate assumes that consistent with current experience, approximately 70% of all recordable injuries result in a Lost Workday Case (LWC), and also assumes that the average days away from work per LWC is 54.5, as was the case in 2008. In 2006, the total expenditures associated with workers compensation and medical costs were $6.8 million. Assuming the Company achieves
this targeted level of improvement, the Company expects some reduction in these costs. Also, it is assumed that as the Company’s overall safety performance improves, the severity of employee injuries will decrease and as such, it is expected that the overall time away from work will decrease as well. Any new costs associated with achieving this safety improvement should be minimal; the emphasis will be on refining existing programs and ensuring strong execution (e.g., better job planning through documented job briefings and job observations).
**Recommendation Number:  59**  
Strengthen enforcement of contractor compliance with their safety programs  
Team Lead(s):  Randy Price

**Summary of Implementation Actions:**

This recommendation is complete.

In response to this recommendation, a multidisciplinary team comprised of members from Corporate EH&S, Construction Management, Gas Operations, Central Support Operations and Electric Operations was formed. The team aggregated and described the current processes for enforcing contractor compliance with their safety programs as defined in their Environment, Health and Safety Plan (eHASP). They determined that contractor management systems are adequately covered in the Corporate EH&S procedure (EH&S Qualifications for Contractor Procurement) and the Contractor Administrative Manual (CAM).

The team also evaluated current safety practices and expectations as defined in the eHASP and inspection programs by conducting a survey of the organizations’ EH&S Managers and an analysis of three years (2007-2009) of Contractor Field Observation Reports (CFOR) related to non-compliance of eHASP and other safety violations.

In addition, the team conducted a gap analysis and identified opportunities for improvement in the following areas:

- Communication with contractors
- Better utilization of the Contractor Oversight System (COS)
- Quality of Contractor Field Observation Reports (CFORs)
- Monitoring of contractors’ OSHA incidence rates, CFORs, Contractor Evaluation Reports, Infraction Reports and Action Lines

Based on the gap analysis, recommendations and an implementation plan were developed to enhance the contractor safety program. These recommendations include incorporating best management practices (BMPs) into the current program. For this effort, BMPs are techniques identified amongst the different departments throughout the Company found to be the most effective and practical in achieving contractor eHASP compliance while making the optimum use of the Company’s resources. The BMPs identified were:

- Intensify communication between the Company organizations and the contractors they hire with regard to field inspection results and their safety performance;
- Enhance training for Company field inspectors and field EH&S organizations so that the quality of field observations and associated reports improve;
• Upgrade the online training module for Company employees and contractors on how to write effective eHASPs;
• Upgrade the training on the use of the Contractor Oversight System in order to more effectively and efficiently capture field performance data;
• Enhance contractor company safety performance evaluations by incorporating COS field data analysis as a supplement to the contractor OSHA Incidence Rates, Infraction Reports, and Action Lines;
• Enforce contractor submission of records on their EH&S trainings, safety supervision and other safety-related activities; and
• Implement the Company’s initiative of “job observation program” on contractors’ work to improve the quality of job planning and job briefing by coaching.

The implementation plan was rolled out to the Company’s EH&S Leadership Team and implementation progress was monitored quarterly (April-June, July-September and October-December of 2010) through self assessment for compliance status by operating organizations. Each operating organization’s EH&S Department completed the self assessment with due diligence, evaluating compliance with the current requirements of the Company’s procedures and the implementation of the recommended best management practices (BMPs).

All operating organizations were found compliant with the requirements of our corporate procedures, CEHSP A12.03 – EH&S Qualifications for Contractor Procurement and Contract Administration Manual (CAM). Construction Management and Gas Operations, who oversee approximately 85-90% of all non-per diem contract work, have implemented BMPs. Other operating organizations have implemented BMPs based on the complexity of the contractor work (Type I & II) as specified in corporate procedure, CEHSP A12.03 – EH&S Qualifications for Contractor Procurement.

The implementation plan also called for a revision of eLearning training modules on Contractor Oversight and the creation of a Contractor eHASP training module. The revision of the Contractor eHASP training module was completed in October 2010. A Contractor Oversight System (COS) training module was completed in January 2011.

The implementation plan was designed to foster a more cohesive contractor safety culture benefiting Company personnel as well as our contractors. Approximately $10,000 in Company labor was spent in developing and implementing recommendations to strengthen enforcement of contractor compliance with their safety programs. The cost associated with revising the Contractor eHASP training module and developing the COS training module was approximately $38,000. The benefits achieved through these training courses and the implementation plan are enhanced control over contractors and their work site conditions, enhanced contractor evaluations, better written contractors’ eHASPs and increased contractors’ awareness on their eHASPs. The benefits are expected to exceed the cost incurred in setting up the implementation plan.
In addition, implementing BMPs across all operating organizations establishes a company-wide commitment to safety excellence and helps us protect the safety of our employees, contractors, and the public. Better contractor oversight identifies and mitigates risks and hazards before we perform work which is an integral foundation of our business plans and operating practices. Engaging company personnel and contractors fosters open communications with our employees and contractors on safety risks.

The Company has already observed improvement in the contractor safety performance since the development of the recommendation implementation plan in January 2010. The contractor OSHA Injury Incidence Rate for 2010 was 1.84 compared to 2.58 for 2009. There were a total of 38 recordable contractor injuries in 2010, compared to 55 in 2009.
Recommendation Number: 60
Establish a corporate philosophy, policies and supporting guidelines for the balancing of in-house and contractor resources.

Team Lead(s): Mary Adamo / Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

The Liberty Audit report notes as part of its overall recommendations for improved resource planning that decisions regarding the use of contractors, despite a lack of stated guidelines, seem to be made on a logical basis at the local level but recommends that formal guidelines be established. The Company benchmarked both internally and externally to evaluate current practices for decision-making related to the use of contractors vs. company work forces. Within the Company, our Central Engineering organization provides formal guidance on the use of contractors. The Company benchmarked how other utilities provide guidance to their workforce on deciding when to use contractors. Surveys were completed and returned by 27 utilities. Of those utilities, 80% did not have formal guidelines or policies in place around the use of contractor resources. Those that did were primarily driven by restrictions in their union labor contracts.

The Company utilizes contractors for project specific, staff augmentation and outsourcing activities. To further the standardization of approach for local organizations making decisions about the use of contractor resources, the Company has developed an HR Guidance Memo that outlines the Company’s guiding philosophy on the use of contractors to obtain the optimal mix of in-house and contractor resources. The HR Guidance Memo on the Use of Contractors to Perform Company Work outlines the factors that should be considered and the process to be followed when making decisions about whether to utilize contractor resources for specific projects, to augment staff, or to outsource functions. This guidance memo promotes standard practices and consistency in this process. It will be communicated across the Company via a Postmaster e-mail to serve as a guide on any projects or programs when considering the use of contractor resources.

The standardized review will be conducted at minimal cost and is already performed as part of existing practices; thus any benefits realized would be net savings. We anticipate cost savings from the use of the standardized guideline to obtain the optimal mix of in-house and contractor resources on various work activities. In the aggregate of all project specific, staff augmentation, and outsourcing activities that the Company utilizes, we believe that we will see savings from this disciplined approach and we expect a positive cost benefit for the Company and its customers.
Recommendation Number:  61
Establish a corporate philosophy, policies and supporting guidelines to provide management and supervisors with a framework to manage overtime.

Team Lead(s):  Mary Adamo / Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

This recommendation focused on enhancements to the management of overtime and providing prudent and effective control of resources consistent with the Company’s mission to provide energy services to our customers safely, reliably, efficiently, and in an environmentally sound matter.

Through surveys and discussions with utility representatives, we benchmarked with five northeast regional utilities that serve similar customer bases. The results of the benchmarking effort did not reveal any new significant overtime control programs in these utilities. The team also reviewed the internal overtime management plans of the four major operating organizations within CECONY. This benchmarking identified several overtime control initiatives that were begun under the guidance of the newly organized Cost Management organization. Several of the identified changes, implemented within Electric Operations, have proven successful in reducing overtime in this organization from the 2nd quarter of 2009 to the end of 2009. Specifically, we noted that budget variance reporting to the section level increased accountability and the visibility afforded management by the segregation of overtime into emergency and non-emergency categories.

Building on this internal effort, we formulated an Overtime Cost Control Policy that will be implemented by each of the respective operating organizations. The policy creates a company-wide standard framework for the management and supervision of overtime resources. The communication rollout and training for implementation will be done in the second quarter of 2010. The following is a summary of the policy’s elements.

In general:

- Charges local management with responsibility for maintaining overtime logs, establishing local policy, evaluating results and developing strategies to improve performance. This framework will add uniformity to the process, while allowing each organization the flexibility to manage its overtime budget. It will also allow for regional differences and needs in the various service areas.
- Charges the Cost Management organization with developing reliable overtime forecasts, reporting, long-term tracking, and investigation authority.

Specifically:

- Creates four standard categories for overtime expense.
- Requires each organization to maintain a local overtime guidance document.
• The Policy authorizes an Overtime Memorandum that specifies the requirements for 
overtime budgeting, variance reporting and tracking for all organizations.
• The Overtime Memorandum also contains provisions for an exception reporting 
process that will allow the Cost Manager of an organization to intervene and hold 
operating General Managers accountable for overtime above predetermined 
margins.

Implementation costs will be generally low as this is a recalibration of administration and 
management functions related to overtimes expenses presently deployed in most operating 
areas. The cost of performing the benchmarking study was approximately $4,000.

The demonstration of potential benefits is discussed specifically in the corresponding 
section of recommendation 62. The largest benefits are expected to be improved overtime 
cost control and increased accountability. Other benefits of this recommendation include 
the creation of a standard format for overtime reporting, analysis and control, and for high-
level historical usage trends correlated to business activity. The Local Guidance Document 
will afford each organization greater structure in making overtime decisions while 
maintaining the flexibility to manage its overtime budget.

As stated in recommendation 62, in 2009, the Company has realized some benefits from 
applying strategic approaches to managing overtime usage resulting in the reduction of 
overtime expenditures from a high of $134 million in 2008 to $106 million in 2009 or a 
reduction of 26% company-wide. Moving forward, we will expand the program that 
produced these results to other operating organizations. We will monitor the progress and 
impact of this expansion, which is expected to exceed the cost incurred for the 
benchmarking effort as well as in setting up this process.

As a metric for tracking overtime, we will continue to track the percentage of overtime 
hours as compared to the amount of straight-time hours. We will also continue to perform 
analyses to determine the root cause of trends for overtime usage, including the 
segregation of hours by type of work performed, and whether the hours were associated 
with response to emergency circumstances or with planned activities. Results from these 
analyses will be used in cost management groups as inputs for forward looking analysis and 
forecasts.

This policy guidance gives managers, supervisors, and other employees a structured 
methodology to follow, especially when making key decisions as part of routine planning or 
in response to emergency situations. With this perspective, the guidance documentation 
for overtime cost control defines a consistent path for managers to follow, not a 
destination.
Recommendation Number: 63
Advance the continuous improvement efforts under the Way We Work Program
Team Lead(s): Mary Adamo

Summary of Implementation Actions:

This recommendation is complete.

Cost management consciousness has been identified as a key cultural change imperative for the Company to be driven by Senior Leadership and will be modeled to be embraced by all employees. Training and communication protocols are two important components to reinforce change in expectations or shifts toward a newly desired culture of cost consciousness/cost management. This means cost consciousness, over time, will be deeply embedded in all actions from planning to execution to celebrating success.

To advance the continuous improvement efforts that emphasize cost management, members of the Way We Work Steering Committee collaborated with the Cost Management team to develop the communications and training components of the cost management implementation plan. The implementation of this recommendation is closely linked to recommendations 46 and 48.

Communications Plan
The communications plan is designed to support the process, training, technology, and organizational changes that comprise the Company’s cost management initiatives. The communications will generate awareness, reinforce the priority of cost management, and support an active approach to monitoring, analyzing and managing costs. Elements of the communications plan include modification of the definitions of the Way We Work principles to include cost management language. Other initiatives include a message board which identifies key messages that will be reflected in communications to all employees, the development of a standard cost management presentation that managers can deliver at organizational meetings, and postmaster announcements to all employees that will communicate Cost Management team initiatives at employee forums.

To sustain these communications efforts, the Way We Work Steering Committee will utilize many of its existing recognition and communications channels to highlight positive examples of cost management throughout the Company, on an ongoing basis.

Training Programs
A training program titled “Fundamentals of Cost Management for Line Managers and Supervisors” is currently being developed and is scheduled to be complete by the 3rd quarter 2010. It is designed to emphasize the accountability of line personnel for cost management, and teach supervisors and managers the fundamentals of budgeting and cost management.
Additionally, we recently developed other training programs related to cost management, including 1) a comprehensive project management program; 2) a course that provides a structured framework for solving problems and improving business process; and 3) a utility finance and accounting class.

The Company also appointed a Director of Cost Management. This position is effectively the program czar for Cost Management, in addition to being the team lead for the Cost Management implementation team. The position reports to the President of CECONY.

There were no additional costs identified at this time to develop the communication plan. The cost to develop the training program “Fundamentals of Cost Management for Line Managers and Supervisors” was approximately $6,700, for the creation of the course outline and material. The other three courses were developed for a total cost of $135,300.

The benefits from these courses include basic training to employees on important analytical, cost and project management principles that are critical for managing the Company’s programs and projects. In addition, these courses will promote and develop better teamwork and group communication, and enhance customer service through improved processes and innovation. The project management course provides a nationally recognized certification in the use of standard practices to manage projects of all sizes and an understanding of detailed work-breakdown structures that support more accurate scheduling and cost estimates.
Recommendation Number: 64
Include pertinent productivity improvement goals in future KPI’s at various management levels
Team Lead(s): Mary Adamo / Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

The Company recognized the importance of influencing organizations with a unified, reasonable approach resulting in attainable units of performance measures. The 2009 productivity and efficiency goals were identified and compared to initiatives that were not being captured as key performance indicators (KPIs) – also known as “gaps.” We proposed models to the organization that assisted with the identification of system efficiencies and cost management improvements. We used existing or enhanced technology to identify and analyze the work vs. time vs. expense. We valued the importance of developing Key Performance Indicators to leverage the respective organization’s fiscal responsibility, innovation, and technical skills.

Activities to date:

- Established KPI ground rules/criteria
- Reviewed current productivity measurement tools in use in various departments
  - Identified any productivity initiatives in the current 5-year plan
  - Identified any productivity initiatives that are not captured as a KPI
  - Identified any current Productivity KPI that is already in place
- Evaluated transparency of data and linkage to departmental KPIs
  - Identified applicable ERM initiatives to our mission
- Identified and addressed gaps
  - Evaluated current procedures and protocols for measuring productivity and efficiencies
  - Conducted benchmarking
- Developed KPI drivers and monitoring methods

Our proposal sets the guideline that:
- the measurement is tied to credible standards;
- performance is measurable;
- the performance measurement is tied to variable pay through the KPI process; and
- the productivity / efficiency directly impacts cost management

The utilization of KPIs is expected to help facilitate achieving the 1%-2% productivity improvement per year.
Recommendation Number: 66
Participate more actively in external information sharing efforts. (Conclusion 10)
Team Lead(s): Lou Bevilacqua / Frank LaRocca

Summary of Implementation Actions:

This recommendation is complete.

The Management Audit concluded that Con Edison has limited partnership in external data sharing and less in external benchmarking. Liberty recommended that the Company participate more actively in external information sharing efforts. Benchmarking would provide the Company unique opportunities to extract fresh ideas, network with professionals in the same industry, identify best practices and learn from any success stories for potential application to the Company. Liberty specifically mentioned that Electric Operations participate in the Electric Utility Cost Group (EUCG) and Public Service Electric & Gas (PSE&G) Peer Panel and Gas Operations participate in the PSE&G Peer Panel.

Prior to this recommendation, organizations throughout the Company participated in numerous information sharing and benchmarking efforts; however the Company had not developed a central repository of these efforts, nor was there any awareness across the Company of the scope or types of efforts in which the Company was engaged. The benefits of increased external information sharing and benchmarking and the internal documenting and communication of these efforts are clear. The search for industry best practices that lower costs is one of the key ingredients for benchmarking.

In response to this recommendation, we evaluated the scope, cost-benefit, and overall value of the current information sharing and benchmarking efforts taking place throughout the Company. In this benchmark effort, we tried to determine whether a centralized approach to external information sharing and benchmarking would be beneficial, how to develop a plan to address the gaps and/or overlaps, and how to develop an approach to share, leverage, and communicate the information and benchmarking data both internally and externally.

We prepared a comprehensive inventory of the benchmarking/information sharing efforts taking place across the Company. We analyzed the inventory data and concluded that the Company’s current information sharing and benchmarking efforts are extensive. For example, Electric Operations and Gas Operations already participate in the PSE&G Peer Panel, and Electric Operations is a member in the EUCG (efforts specifically suggested in Liberty’s recommendation). This inventory was published to an internal web site to facilitate sharing this information internally. The site includes:
An inventory of the Company’s current information sharing and benchmarking efforts describing each effort’s purpose along with the participants and their contact information;

A matrix which maps the inventory to a standard utility process model which was used to support gap/overlap analysis;

A set of benchmarking best practices with a benchmarking handbook published by the Department of the Navy which provides useful guidance and information for those involved in planning or conducting benchmarking projects.

To ensure that the Company extracts the greatest value from its future investments in information sharing and benchmarking, the Company’s Business Improvement Services (BIS) group, whose mission includes cost management, will ensure that the inventory of information sharing and benchmarking efforts is kept up to date and accessible throughout the Company. Besides publishing the inventory, the BIS group will perform an annual review of these efforts to identify significant gaps or overlaps in our efforts, along with publishing a set of best practices to help ensure the Company receives maximum benefit from its benchmarking investments. A Company-wide Postmaster announcement detailing the efforts of this initiative and how this information is being made accessible to employees was published in September 2010.

The implementation team consisted of existing Company employees and required no additional costs beyond the labor to perform functions and milestones. Early in the process, we received a scope of work and price quote of $75,000 from Gartner Group (a consulting group) to create a business process framework for prospective benchmarking activities including scope, organizational roles and responsibilities, and management processes. We determined that it would be more cost effective to develop this framework using internal resources. The cost of performing this work internally was approximately $30,000, with an estimated annual cost of $15,000 for maintaining this information.

We expect to realize savings that will exceed the cost of the initial implementation ($30,000) and the annual maintenance costs ($15,000). The Company expects to receive various benefits through the enhancement and organization of information sharing and benchmarking efforts at Con Edison. This resource provides a location where people can go and find out what other benchmarking efforts are currently ongoing and promote discussion about what others have learned through benchmarking. We anticipate that this sharing of benchmarking information and best practices will affect various areas of the Company through implementation of better processes, tools and technologies to improve decision-making, and yield savings as a result. We expect these savings to exceed the initial and ongoing costs of managing this benchmarking effort. We expect that it will also enhance our commitment to continuous improvement at the Company.
**Recommendation Number: 81**
Revise the performance measures (KPIs) for Energy Management to provide metrics and incentives that align with electric procurement objectives. (Conclusion 4)
Team Lead(s): Joe Oates

**Summary of Implementation Actions:**

This recommendation is complete.

Electricity Supply reviewed its electric procurement objectives and incorporated a number of changes to the KPIs for 2011, including four new KPIs. The changes include new KPIs for each section within Electricity Supply: Electricity Hedging and Market Analysis (EHMA), Electricity Supply and Scheduling (ES&S), and Electricity Billing and Analysis (EBA). The primary objective of these new KPIs is to continue to improve the processes in Electricity Supply to help manage customer costs.

In the ES&S section, we combined two existing KPIs (‘Effectively Manage Linden Cogen Optionality’ and ‘Effectively Manage SCS Astoria Off-Peak Energy Optionality’) with two new KPIs (‘Effectively Manage Indeck Dispatch Optionality’ and ‘Effectively Manage Selkirk Dispatch Optionality’). These four KPIs are now a single, weighted KPI that incents Electricity Supply to ‘Effectively Manage Non-Utility Generator (NUG) Contract Optionality.’ This metric measures the effectiveness with which ES&S dispatches the NUGs on an hourly basis when compared to market pricing. This helps ensure Electricity Supply manages the provisions of each NUG contract to provide customers with the lowest possible electricity supply costs. The new metric sets a benchmark for measuring how effectively ES&S makes these dispatch decisions.

In the EBA section, we added a new KPI to ‘Improve the Accuracy of CECONY Supply Cost Accruals.’ Each month, electric transaction costs for the month are estimated to generate an accrual to recognize expenses on the financial statements of CECONY and recover electricity supply costs from customers. The following month, a reconciliation of actual costs compared to the estimate is prepared. The difference between the actual and the accrued amounts are known as a billing adjustment. Billing adjustments occur for a number of reasons, including cases where contract pricing terms are not fully known at the time of the accrual (e.g., for NUG gas costs), variations between estimated volumes known at the time of the accrual and actuals reported some days later (e.g., month-end meter reads), and errors. The lower the billing adjustment is, the less variation there is to the Company’s financial statements and customer bills. The new metric will track the cumulative annual billing adjustments and sets a benchmark for adjustments.

In EHMA, a new KPI was added to ‘Expand the Number of Counterparties for Financial Hedging.’ Expanding the number of counterparties for Electricity Supply’s financial transactions increases the opportunities to obtain the most competitive pricing for
customers. This indicator measures activities associated with adding new counterparties through a two-part indicator. One-third of the indicator requires providing the Company’s ISDA contract “special provisions” to at least 10 counterparties during the year. These provisions form the starting point for negotiations and are generally not readily accepted by counterparties, but require further discussions between the legal departments of the Company and the counterparty. The remaining two-thirds of the indicator is based on the number of contracts executed during a year.

The fourth new Electricity Supply KPI requires an ‘Update of the 10-year Electricity Supply Plan.’ The 10-year Electricity Supply Plan will assess the medium-term future supplies of energy and capacity for CECONY full-service electric customers. It is intended to cover a 10 year period that focuses on the supply versus the Electric Hedge Plan which covers up to 3 years. The scope of the plan will be to examine the physical demand/supply balance, the financial implications of various scenarios and cost control opportunities for CECONY full-service electric customers. Additionally, it will serve as a planning tool and guidance for decision points regarding possible market and supply changes in the near future. The new KPI requires that the plan be presented to management at various levels and comments/recommendations be incorporated in the plan in order to meet the target. This KPI incorporates Recommendation 80 into the annual deliverables for Electricity Supply. This KPI is also combined with the Gas Supply Plan update as a new KPI for the vice president of Energy Management.

These changes to the KPIs for 2011, i.e., the addition of the four new KPIs discussed above to the existing Energy Management KPIs, further promote the alignment of Energy Management’s electricity procurement objectives and management compensation.

Implementing these KPI changes does not require any additional resources or expenditures. The primary benefit of these new KPIs is that they will provide metrics that enable Electricity Supply to continuously improve its processes to help manage customer supply costs. To the extent that these new KPIs result in operational benefits or improvements in Electricity Supply, all resulting cost reductions will be directly passed on as they occur, in the form of reduced supply costs to our customers.
Recommendation Number: 24
Evaluate reliability programs to determine if they should be terminated earlier to release capital expenditures for more cost effective reliability programs.
Team Lead(s): R. Schimmenti, R. Bozgo

Summary of Implementation Actions:

This recommendation is complete.

Distribution Engineering has adopted an improved prioritization process to ensure infrastructure investments and longer-term reliability projects are systematically addressed in developing capital investment plans. In early 2009, CECONY began detailed analysis of various programs to ensure investment is prioritized to meet system performance needs. This approach results in a quantified cost-benefit analysis to target investment to those programs yielding the greatest projected benefit for a given investment. These cost-benefit relationships provide an effective means of gauging program effectiveness across varying levels of investment by indicating levels of maximum benefit per dollar and also levels at which diminishing returns for investment begin to appear.

Curves and performance targets help optimize program investment. Calculated benefits of a program’s contribution to risk reduction and achievement of strategic objectives are used to prioritize programs and to dictate investment across programs. These metrics, embodied in Efficient Frontier Curves, are valuable to be able to allocate funding according to cost-benefit relationships. Each program is demonstrated by one of these curves, and relationships among programs are evaluated to determine optimal investment. By being able to describe programs in terms of risk and strategic value, or just risk, or just strategic value, trade-offs can be evaluated for prioritization.

Engineering planning organizations utilize a tiering process to evaluate relative ranking of benefits, to identify and rank programs that yield different levels of benefit for dollars spent, and to determine the extent to which a program should be implemented. Tiering supports decisions to continue, expand, contract or eliminate programs. It also provides a consistent basis to establish requirements for the development and phase-in of replacement programs.

In support of the 2010 Capital Budget Process, 21 electric distribution capital reliability programs have been targeted for the development of cost-benefit analyses. These
programs total approximately $264 million and represent over 75% of the total 2010 System Relief and Reliability budget request of $351 million.

In addition to representing a significant proportion of the 2010 budget, these programs were selected based on the following hierarchical criteria:

1) Net benefit index was determined by a combination of the Risk Priority Number (RPN) and Corporate Strategic Objectives (CSO). The RPN metrics and CSO categories are supplied through the Enterprise Risk Management committee and provide high level guidelines to assist in the prioritization of programs. These guidelines quantify each program’s relative impact on the likelihood, severity, and controllability of specific system events;
2) Data availability;
3) Anticipated positive impact per dollar spent on system performance.

Additionally, an overall portfolio analysis of the Distribution programs completed under this initiative is currently being undertaken and refined. The portfolio analysis will provide for an analytic means of quantifying the optimal collective benefit realized through targeted programs and direct any re-allocation of capital expenditures among programs to satisfy the optimal benefit.

To date, 11 of the 21 electric distribution capital reliability programs, collectively totaling around $204 million, have been represented by cost-benefit relationships with program-specific reliability enhancements being used to quantify the benefit aspect of the program. Although these cost-benefit relationships have not indicated the total termination of any one program, they have provided direction for the re-allocation of capital expenditure among the programs in order to optimize aggregate system improvement thus providing more benefit per dollar to the customer. They have allowed for the measured contraction of 8 programs by about $40 million. Additionally, the relationships supply quantitative guidance regarding long-term program expectations and potential points of diminishing returns.

The Company has also developed a system reliability model that shows relative risk contribution associated with various substation assets. The analytical process is augmented by peer teams of subject matter experts that evaluate equipment status and optimize maintenance and replacement programs for critical assets. The peer team initiatives have resulted in changes in the scope and frequency of equipment maintenance, overhaul, and replacement, increased condition monitoring, and improved maintenance processes. Programs for critical transmission assets have been analyzed for their reliability impact and cost-effectiveness. Our ongoing efforts have allowed us to realize $24 million in savings in 2009 for the transformer and breaker programs.
Engineers are often required to draw upon various applications and disparate data sources to gather information for analysis and studies. The Engineering Dashboard will bring together various data sources and assists engineers with event and performance analyses. This solution, which will be utilized by Electric Operations, is being developed by TIBCO Company under the guidance of Distribution Engineering.

The Engineering Dashboard will be a platform that integrates data from sources such as Plant Information (PI), the Feeder Management System (FMS), Power Quality (PQ), and Cable and Joint Analysis Control System (CAJAC). The Dashboard will be to make it easier for engineers and other users to analyze system performance, and will provide tracking and pattern recognition and notifications relating to performance. The three main parts of the Dashboard are:

- Data Integration and Static Dashboards
- Patterns
- Analytic Visualization (for ad hoc query)

Data will be collected, transformed and aggregated from multiple data sources to form the Engineering Dashboard. A distributed data grid stores the data optimally so that complex patterns can be detected and the growth in volume of data can be handled. Static dashboards, which are provided for various reporting requirements, will be available based on pre-defined cases.

The Engineering Dashboard will have the ability to detect anomalies based on pre-defined tolerance levels, defined by our engineers, followed by alerts through channels such as e-mail. This ability ensures continuous information, allowing continuous control and improvement. The pattern detection can be done real-time and, as the work on the Dashboard continues, can be designed to be predictive.

The data populating the Engineering Dashboard will be configured in a standardized way to support use with analytic software such as Tableau. The ability to utilize Tableau to access the data will provide a user friendly way to run ad hoc queries. In addition, Tableau has the ability to graphically analyze the populated data and produce charts, graphs, and reports, which will assist in providing insights to the data.

The pilot demonstration of the Engineering Dashboard was completed in April 2010 to be followed by a six-week testing period. During this timeframe, the Dashboard will be tested by engineers who are presently carrying out analyses by utilizing many different data sources. After the testing period is complete, the application is expected to be placed into production.
Recommendation Number: 25
Analyze networks and the 138 kV system designed to N-1 standards to determine the extent that maintenance activities can be performed at load levels less than peak load; where appropriate, incorporate maintenance design requirements into relevant design standards.
Team Lead(s): R. Schimmenti, R. Bozgo

Summary of Implementation Actions:
This recommendation is complete.

A study of the Company’s auto-loops has been completed and the review revealed that all 152 Company auto-loops are presently equipped with emergency back-up feeders that provide for an N-2 design.

Only 18 of the auto-loops are also designed to an N-2 and can be reconfigured using manual switching, minimizing the possibility of dropping load. Based on the past performance of the 18 auto-loops that have manual emergency tie switches and established Company procedures regulating maintenance work, the capital expense to install SCADA ready or automatic switches on these 18 auto-loops is not cost justified. Maintenance work on the auto-loops is always planned and performed during non-peak load conditions. Company specification EOP-5025 prohibits scheduled work from being performed during peak load conditions as determined by load or temperature variable. Emergency tie feeder availability is always part of the scheduling review process to ensure their availability. The Company has included on all the auto-loops emergency tie feeders which are used to normalize or reconfigure auto-loops minimizing the possibility of dropping load when performing scheduled work.

The cost of the 138kV system and distributed auto-loops studies were nominal and the studies were able to confirm the adequacy of existing maintenance procedures during non peak periods to ensure no impact to customers.

The Company has long recognized that the placement of emergency feeders and tie switches placed at strategically selected locations on the auto-loop systems help to support reliability. The manual emergency feeder tie switches on the 18 auto-loops can be upgraded to automatic or SCADA ready switches at a cost of approximately $1 million dollars. However, based on past the performance of these 18 auto-loops, this upgrading is not justified since these auto-loops have performed reliably. The Company will continue to annually evaluate if additional emergency tie feeders or switch upgrades are warranted and are cost justified.
**Recommendation Number:** 26
Clarify transmission planning criteria with regard to transfers used during second contingency analysis. (Conclusion 8)
Team Lead(s): R. Bozgo, R. Schimmenti

**Summary of Implementation Actions:**

This recommendation is complete.

We have reviewed our criteria within the context of our controlling and regulatory authorities, including the New York Independent System Operator (NYISO), New York State Reliability Council (NYSRC), the Northeast Power Coordinating Committee (NPCC), and the North American Electric Reliability Council (NERC) to ensure that our practices are in full compliance with their requirements. In addition, we have compared our transmission planning criteria to those of our neighboring utilities in New York State, which include LIPA, O&R, and Central Hudson to ensure consistent and common practice. Our criteria conform to those of these national, regional and state reliability organizations and RTO’s (Regional Transmission Organization).

We have updated our Transmission Planning Criteria to better clarify transfer limits as follows; “to the extent that the ten-minute operating reserves within the Con Edison service area are not sufficient, then ten-minute operating reserves from outside the Con Edison service area will be utilized, thereby resulting in an increase of transfer levels.”
**Recommendation Number: 27**
Perform a global review of all equipment ratings, input data, and time durations across the distribution and transmission areas to assure consistency and to justify and document differences.
Team Lead(s): R. Schimmenti, R. Bozgo

**Summary of Implementation Actions:**

This recommendation is complete.

The Company performed a thorough review of all of its equipment rating methodologies, including input data and time durations across the distribution and transmission systems. The parameters affecting the rating of equipment are dependent on the type of equipment, temperature limitation of insulated and current carrying materials, load cycle (daily load variations), emergency duration, ambient temperature, and system design.

A report was prepared that links the equipment rating specifications to the input parameters and provides a detailed review of our rating methodologies. Our general practice is to keep equipment ratings consistent with industry standards and guidelines, and differences were documented and justified in the report. More specifically, differences were a result of variations in the input parameters: equipment temperature limits, load cycle and emergency rating duration and ambient temperature. Some modifications to the standards were adapted to better represent the thermal conditions equipment experiences in the field.

In addition, a review of the ambient earth temperatures used for the thermal ratings of all system equipment is being performed to determine whether a standardized temperature can be applied. Because the ambient earth temperature study had begun prior to this recommendation and is in the phase of data analysis, no additional cost has been incurred. The results of the study will provide more representative temperatures for the underground environment, which will produce more realistic equipment ratings. The benefit is that equipment is neither underrated, resulting in unnecessary load relief work, nor overrated, resulting in possible equipment overloads during high load periods.
Recommendation Number: 28
Maintain the 2011 completion date for completion of network secondary topology updates and EPRI DEW software.
Team Lead(s): R. Schimmenti, R. Bozgo

Summary of Implementation Actions:
This recommendation is complete.

Secondary Visualization Modeling
The Secondary Visualization Modeling (SVM) project includes the development and operation of distributed secondary network load flow models using Poly Voltage Load Flow (PVL) software. Distributed models are used to develop a planning case for scheduled reinforcement and replacement of network components, and have been used to develop planning cases for 2010 and 2011.

The Secondary Visualization Modeling project has successfully developed and implemented a new five step standardized process to create distributed secondary models for all the networks. This new process is being utilized to complete secondary models for all underground distribution networks. It ensures that the secondary models accurately represent the network secondary configuration to support an accurate secondary load flow analysis. As a part of the SVM project, the Company issued a specification to detail the standardized process to create models in the Poly Voltage Load Flow program.

The previous technique for modeling network loads in PVL constrained the analysis of secondary load flows. This technique connected the load extracted from the Company’s remote monitoring system at the transformer low voltage bus for the distributed network. This method was not an accurate representation since the loads on the secondary grid are distributed and not concentrated in one point at the transformer location.

The newly developed distributed secondary models will accurately represent the secondary load flow analysis by distributing the load at the service point. As a result, the secondary distributed models will provide loadings on all secondary main sections in a network under all possible combinations of first and second contingency for the network peak.

The benefits of the new five step approach include more efficient engineering design and analysis of the secondary load flow, an automated process of identifying and correcting secondary mapping error, prioritization of secondary main replacement based on risk analysis, and optimized design of network grids. The increased refinement of the new secondary load flow allows for more targeted identification of overloads which will result in reduced reinforcement expenditures.
A comparative analysis of the former modeling method of concentrating demand at the transformer and the new distributed demand process demonstrated that refined distributed demand model resulted in fewer overloaded primary section and transformers. The analysis of the two modeling methods was completed on four Bronx networks and judged against a common load background. The approximate cost of developing these four distributed demand models was $450K; the reduction in overloads resulted in $1.8 million dollar savings in system reinforcement spending. Within this analysis, the Company realized a savings of approximately $1.35 million.

EPRI DEW
At the time of the Management Audit, Con Edison was in the process of testing the Electric Power Research Institute (EPRI) Distributed Engineering Workstation (DEW) software for broader implementation across its electric operations business units. DEW is an analytical software product that is used to model power systems and solve power system equations. Liberty noted that Con Edison was utilizing this DEW software to enhance its distribution planning analytical capabilities, and that further implementation would benefit the Company by providing more accurate results as inputs into its distribution planning processes.

The evaluation of the DEW software for use on Con Edison distribution systems continued after the Audit Report was published, and this evaluation concluded that the DEW software did not meet CECONY’s technical requirements. The evaluation highlighted DEW’s inability to show proper load sharing at isolated networks and high tension installations or give correct voltage and current profiles of all feeders. The evaluation consisted of two parts. The first part involved testing DEW software using a model of the Staten Island Fresh Kills load area, and the second part involved testing DEW software with the IEEE Standard Systems by Polytechnic Institute of New York University. During the first part of the evaluation, 15 unique load flow cases of the Fresh Kills load area were run twice to determine if identical results would be achieved in both runs of each case. DEW software failed to duplicate results in any of the cases. The evaluation determined that DEW software failed to give correct and consistent results, and would require extensive work in order to satisfy the Company’s distribution modeling needs. As a result, we decided to evaluate other tools and applications presently on the market to meet our business needs and concurrently satisfy Liberty’s recommendation.

Additional software products from both Siemens and CYME were evaluated and found cost effective to complement the Company’s existing modeling process. By using these products, in conjunction with existing Con Edison modeling and analyses, single-phase and balanced and unbalanced three-phase load flow analysis can be performed and more accurate feeder cable ratings can be determined. More accurately rated cable will allow for more targeted reinforcement/replacement work. In addition, the Siemens program gives Con Edison engineers the ability to perform single-phase, and balanced and unbalanced three-phase load flow analysis. Implementation of the combination of these Siemens and CYME products satisfies Liberty’s recommendation, and yields additional benefits for a lesser expected cost when compared to the recommended continued implementation of DEW.
The Company has distributed these Siemens and CYME products for use throughout the Company, and has performed extensive training sessions to educate users on its operations and capabilities.

The adoption of Siemens and CYME products improves our engineering and control center operations and analysis. Siemens and CYME products, in conjunction with existing Con Edison modeling and analyses, provide the capability of performing single-phase and unbalanced three-phase load flow analysis as well as more accurate feeder cable ratings.
**Recommendation Number: 29**

Perform a least cost system analysis that minimizes costs to customers with regard to implementation of 3G strategies.

Team Leads(s): R. Schimmenti, R. Bozgo

**Summary of Implementation Actions:**

This recommendation is complete.

The goal of the 3G System of the Future is to develop innovative strategies that can achieve lower cost, reliable system design over time. The key strategies, or design concepts, that achieve cost reductions include substation asset sharing, distribution load transfer, feeder reconfiguration, low voltage network migration and smart grid implementation. Each of the concepts facilitates operational flexibility to optimize resources and respond to contingencies. Leveraging flexibility among assets can be used as alternatives to conventional system reinforcement and can ultimately eliminate or defer capital expenses and reduce O&M expenses. The 3G concepts also aim to reduce risk throughout the system which will ultimately benefit customers from a reliability standpoint as well as avoid costs associated with adverse system events. As new design alternatives are developed for future load relief and capital projects, cost benefit analyses are performed for the 3G and conventional designs to select the best option.

3G applications have been developed for future system designs to reduce cost. During 2009, in collaboration with the development of the Electric System Long Range Plan (see recommendation 5) and as part of an effort that will continue throughout future years, Con Edison evaluated 3G options for cost-benefit against traditional substation designs. Metrics for cost savings included comparison of project costs and evaluation of opportunities for deferral of capital investment. While these long-term cost estimates and comparisons will need to be modified to meet changing economic and system conditions, they provide a foundation for analysis and planning, and can be monitored in the future and used as decision criteria.

Using substation asset sharing and distribution load transfer concepts, proposed 3G designs for York area substation and Eastern Queens transmission area substations are expected to yield present value cost avoidance over 30 years of $61 M and $397 M respectively, when compared to conventional designs. Cost savings are also expected for alternative 3G options to the Hudson Yards and Gowanus transmission substations. A concept to migrate away from the low voltage network has been incorporated into the procedure for new customer connections, where applicable.

An innovative design to utilize intelligent medium voltage switches and intelligent underground auto-loop configurations was applied to the Flushing Network to reduce the risk of a large network outage. This design is a lower cost option, and uses a novel approach.
to reduce the risk of a large outage by reducing both the likelihood and the severity of an outage. The design is part of the DOE Smart Grid Stimulus Deployment Grant, and will be implemented over the next three years.

Based on the 2009 ten-year load relief plans, preliminary 3G designs have been developed to implement switching and feeder reconfiguration in distribution networks. Two 3G designs were identified to be most promising and will be used by Distribution Engineering for a comprehensive review, including detailed cost / benefit and a full engineering analysis to evaluate the impact of the proposed design on the distribution network, the operational and safety procedures involved, and the practicality of implementation. These designs have the potential to increase operational flexibility and reduce risk.

Many 3G designs will reduce the risk of adverse system events. To capture this benefit so it can be considered in the least cost analyses, a risk assessment was performed considering a specific event and case study. To capture the risk benefit for other network events, a similar methodology was developed. This will be used to evaluate the risk reduction benefit of 3G designs for least cost options and implementation.

In March 2009, a formal Engineering Operations Manual was issued to formalize the annual review for 3G alternatives in the capital review process. Going forward, the development of 3G concepts to replace conventional design and provide lower cost options will be a regular step in annual capital planning.
**Recommendation Number: 30**
Perform analyses to determine if peak demand can be reduced more economically than the addition of infrastructure.
Team Lead(s): R. Schimmenti / R. Bozgo

**Summary of Implementation Actions:**

This recommendation is complete.

The Company performed a number of studies in order to determine the peak load reduction potential as well as the cost benefit and feasibility of each topic outlined in Recommendation 30.

1) Analysis of system and network peak reduction potential of the current and proposed Con Edison Energy Efficiency programs, and the Con Edison and NYISO demand response and ancillary services programs.
2) Analysis of balancing phases on the radial system.
3) Analysis of implementing power factor correction on the overhead primary system.
4) Analysis of implementing incremental voltage reduction to control system peaks.

Each of the topics above was reviewed for its ability to reduce system or network peaks. The advantages of peak shaving are:

- The potential to defer or avoid infrastructure upgrades otherwise required to meet anticipated peak hours loading on network or associated transmission supply feeders, or
- To reduce the increased ($I^2R$) line losses associated with higher loads.

External consultants were engaged to evaluate the potential for reducing load via efficiency and demand response. The other efforts were studied in-house for their potential to reduce losses or achieve peak shaving (i.e. peak demand reduction), and then compared to the cost of either taking no action or to the cost of comparable load relief methods. It should be noted that alternative costs for upgrades to transmission, sub-transmission feeders, and area substations are case specific.

Additionally, a review of the Emergency Operating Systems (EMOPSYS) database was performed. The Con Edison EMOPSYS database logs customer sited emergency generators, customers with Life Sustaining Equipment (LSE), and other critical customer systems. The EMOPSYS database was assessed to determine, by network, where customer sited generators might be available for peak shaving programs. The database has been shared for use with Energy Efficiency (EEPS) programs.
1) Analysis of the system and network peak reduction potential of the current and proposed Con Edison Energy Efficiency programs, and the Con Edison and NYISO demand response and ancillary services programs

The current and future potentials for Demand Response and Energy Efficiency programs were assessed in separate studies completed in 2008 and 2010 respectively. The Company’s 2009 filing for a suite of new demand response programs was adopted, in part, by the PSC. The programs were designed, among other things, to demonstrate the ability of demand response to defer load relief projects. These programs were supported by the demand response potential study, and pilots began for the summer of 2010. The Company filed program revisions in September 2010 to improve program participation. The Company also filed for a continuation of its successful Targeted DSM program, which has used permanent demand side measures (such as efficiency, distributed generation, and fuel switching) to defer load relief projects since 2005.

Con Edison continues to refine its programs to better integrate and leverage efficiency, demand response, distributed generation, and energy storage solutions in order to defer infrastructure. In particular, as part of its filing to extend the Targeted DSM program, Con Edison has proposed new approaches to leverage Company and NYSERDA Energy Efficiency Portfolio Standard (EEPS) achievements to reduce demand in constrained networks and increase the number of infrastructure projects deferred by these programs. The 10 Year Load Relief Plan shows the projected load forecasts then separately lists, for planning purposes:

- Projected DSM targeted to specific networks
- Projected Con Edison EEPS MW, which are discounted (due to the fact that the network where EEPS MWs will be achieved is unknown)
- Projected NYSERDA achievement, which is discounted
- 7 MW of known NYPA EEPS projects

2 Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, Order Adopting in Part and Modifying in Part Con Edison’s Proposed Demand Response Program, issued and effective October 23, 2009
3 Case 09-E-0115 - Proceeding on Motion of the Commission to Consider Demand Response Initiatives, Petition of Consolidated Edison Company of New York, Inc. for Approval of a Targeted Demand Side Management Program, dated September 1, 2010.
The numbers are updated for each year’s 10 year plan. Cost-benefit analysis of the Targeted Program is included in a filing currently pending with the PSC\(^4\). The Total Resource Cost (TRC) includes: program administration, evaluation, and incentives paid to contractors and customers. Benefits include avoided energy, demand, and losses as well as environmental and avoided transmission and distribution benefits.

Company projections, in the August 31, 2010 filing, indicated the program will achieve a TRC\(^5\) of 2.7 and create $345 million of net savings (2010 Net Present Value (NPV)) for utility customers, including $223 million in carrying charges on avoided capital expenditures for transmission and distribution upgrades and the balance attributable to customer energy savings, reduced capacity requirements, reduced line losses, and reduced emissions. The TRC was calculated in accordance with the methods approved in the EEPS proceeding, except that the T&D deferral value of $100 per kW will be replaced by the appropriate savings in carrying charges for the specific transmission and distribution project being considered for deferral. Where other programs (e.g., EEPS programs) are leveraged via an added incentive or added marketing, the benefit was calculated considering only the excess transmission and distribution deferral value. This excess value will be defined as the deferral value of the specific transmission and distribution project being considered minus the $100 per kW value allocated to the approved EEPS program(s). The expected benefit cost ratio stated in the August 31, 2010 filing is 2.7; however, the current actual TRC is 3.1 due to our costs decreasing while benefits remained the same.

2) Analysis of balancing radial system phases
An analysis was performed on balancing primary feeder phases in an effort to lower the losses on the feeders in order to increase capacity and defer capital investment. The analysis assessed the potential annual cost savings on six radial feeders in Staten Island. The balancing of primary phases for the six Staten Island feeders resulted in a minimal savings as a result of reduced line losses.

The cost benefit analysis for phase balancing was developed by assessing six radial feeders in Staten Island. Each case was based on real time current readings taken on each of three phases at 18:00 on August 20, 2009 - prorated to an 86°F Temperature Variable Day, which is the Company’s design basis. Current flow on the three phases of the same six feeders was then modeled as if the two phases with the greatest difference in loading were switched. The kW difference in losses between the “as is” and the modeled balanced feeders was calculated assuming a feeder resistance of 1 Ohm. Since the losses would have been permanently reduced by the phase balancing (until an imbalance reappeared due to


\(^5\) The Total Resource Cost measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The TRC is represented as a benefit-cost ratio.
changes in customer use) the benefit was based on the annual avoided cost of supplying the kW of lost energy versus the cost to perform the phase balance moves. However, the cost benefit value is minimal.

3) Analysis of implementing power factor correction on the overhead primary system
Capacitors are widely installed in distribution systems for reactive power compensation to improve the efficiency of power distribution via real power and energy reduction, to improve service quality via voltage regulation, and to achieve deferral of construction, if possible, via system capacity release. The extent of these benefits depends greatly on how capacitors are strategically placed in the system. Capacitors are designed and scheduled for installation at those locations that show the greatest benefit for expected installation costs. As a result, an iterative load flow analysis is completed to determine the optimal capacitor location and size for each installation.

Under the 4kV Grid Modernization program, funded by the Department of Energy (DOE) Smart Grid Investment Grant, the Company will install a total of 247 MVAR in distribution capacitor installations, at a cost of $15 million. Each such individual scheduled capacitor installation was reviewed during the design process to ensure that forecasted system benefits justified cost. In total, these installations will result in an estimated total losses reduction of 6,151 MWh based on the evaluation of the targeted 4 kV feeders. This 6,151 MWh reduction represents $0.5 million in annual energy cost savings. In addition, the ‘optimized’ 4kV distribution grid will result in system reinforcement capital investment deferrals due to a net 61 MW increased peak loading capacity at the 4kV unit substations. The increase peak loading capacity will defer approximately $10 million capital deferment over a five year period at the end of the program. At the conclusion of the five year period, the installation of the capacitors under the 4kV Grid Modernization program will realize a benefit totaling approximately $12.5 million.

4) Analysis of implementing incremental voltage reduction to control system peaks.
The Company conducted a study to demonstrate the potential for peak reduction through voltage reduction. The Company utilized its Voltage Reduction Model to illustrate the impact on electric loading that would result from a voltage reduction program which could be called during peak demand or during periods of insufficient capacity on the utility’s feeder lines and / or power substation, or as a seasonal tool for planned peak shaving. The amount of reduced power was calculated through the use of software developed by Con Edison’s consultant, Polytech University. The analysis identified the MW reduction obtained by a 3% and 5% voltage reduction.

Under this analysis, each network was modeled for a 5% voltage reduction, using Con Edison’s Voltage Reduction Model, with a resulting 2.5% - 2.8% MW reduction. A table interpolating to a 3% voltage reduction shows the available peak shaving for each network. The analysis compared the relative impacts on both primarily residential and non-
residential customers. For this analysis, the benefit of peak shaving by network was compared to the cost of using a mobile generator to supply the substation since this is an option typically used by the Company for the short term load relief that would be used in lieu of temporary or seasonal voltage reduction.

Conclusions of Studies Performed

1) The Company recognizes the potential of demand side management to defer infrastructure and has incorporated it into both the existing Load Forecasting and Load Relief planning processes, and its Electric Long Range Plan.

2) The Company identified a small cost benefit for phase balancing. As a result, it will only be employed in specific cases.

3) The Company identified a positive cost benefit for the installation of distribution capacitors, and has begun installing them under the 4kV Grid Modernization program.

4) Voltage reduction is not utilized as a planning tool to reduce capital infrastructure, because the effects of voltage reduction are a function of the load composition and the demand response to voltage of the individual characteristics of the loads which are not under the Company’s control, however voltage reduction is utilized for operational purposes.
**Recommendation Number: 31**

Actively pursue the economic use of SCADA controlled network feeder sectionalizing switches or circuit breakers to reduce system investment.

Team Lead(s): R. Schimmenti / R. Bozgo

**Summary of Implementation Actions:**

This recommendation is complete.

The strategic deployment of SCADA equipped sectionalizing switches results in the reduction in feeder loading experienced during a contingency. This will result in less reinforcement work to replace feeder components and, therefore, capital savings. Because SCADA operation avoids increased loading on alternate components, critical components do not require reinforcement in order to remain in service. Specific cost savings will be dependent on load growth in a particular network, the loading levels of existing components, and the planned reinforcement activity.

In addition, more cost-effective risk mitigation initiatives could be achieved and associated installation costs avoided with SCADA equipped sectionalizing switches. This result argues favorably for combining SCADA control with switch installation.

In order to provide for a targeted deployment of the SCADA controlled switches, Network Reliability Index (NRI) analysis was carried out and completed. Through this process 99 locations were identified for installation of switches.

Six P&T, one O&M, and one multi-page installation specifications have been issued. The installation specification provides field crews with detailed instructions on how to install and test the various SCADA components. The O&M specification provides the requirements for operations and maintenance of the SCADA equipment and switch. The six issued P&T specifications collectively cover the technical requirements for the underground and above ground SCADA equipment.
**Team 11 – Gas and Steam Planning**

Executive Sponsors: Claude Trahan and Saumil Shukla

Recommendations: 36, 37, 38, 74, 75, 76, 77, and 78

**Recommendation Number: 36**
Evaluate potential changes in the business environment for each of the businesses; for the GBU, Strategic Planning should advise Gas Engineering regarding potential demands on the gas transmission and distribution systems occasioned by those changes. (Conclusion 16)

Team Lead(s): Ed Foppiano

**Summary of Implementation Actions:**

This recommendation is complete.

The Gas Long Range Plan has been finalized with a detailed analysis on the demand and supply of natural gas. Our long range plan describes our intent to serve our customers cost-effectively with safe and reliable natural gas. Public and employee safety is paramount to the way we manage and operate our gas system. It also provides a strategic framework for implementing our plans to manage demand and supply, invest in our infrastructure, provide environmental stewardship, and serve our customers at a reasonable cost.

As part of the effort to prepare the long range plan, we developed a capital investment database and custom analytic model to systematically evaluate the impact of specific programs and initiatives over the 20-year planning horizon. The forecasted capital investments were each evaluated in terms of their incremental impact on the performance, cost, and risk characteristics of the Con Edison gas system.

- Performance measures include system reliability (measured by system availability) and environmental impact (measured by methane emissions)
- Cost measures include savings of capital and operations and maintenance expenditures when compared to traditional solutions as well as the rate and bill impact of those investments
- Risk reduction is measured within the analytical model based on system integrity (incoming leak rates and leak backlogs) and outside the model with various public and employee safety initiatives

These measures are consistent with the Company’s asset management practices, annual asset prioritization process, and enterprise risk management (ERM) process. The Company develops strategies to mitigate the cost increases indicated by the plan. Each of these facets of the Company’s planning and prioritization methods are described in more detail in the GLRP.
The gas long range plan was prepared in cooperation with the Bridge Strategy Group at a cost of approximately $1,000,000. The concepts within the plan enabled the Company to defer beyond the 20-year plan horizon, a multi-year, gas transmission project, for a savings of $75,000,000. This project was eliminated in the Gas Rate Case with compatible system benefits being received from the new pipeline interconnect in Lower Manhattan. Going forward, these concepts will be the guiding principles in achieving future reductions/cost savings.
Recommendation Number: 37
Report to stakeholders and the NYPSC on any expansion of the transmission and distribution systems required to serve winter-period electric power generation. (Conclusion 18)
Team Lead(s): Ed Foppiano

Summary of Implementation Actions:

This recommendation is complete.

The Gas Long Range Plan has been finalized with analysis provided for any expansion of the transmission and distribution systems required to serve winter-period electric power generation.

New York’s existing generation fleet is expected to change in capacity and mix through 2030, mainly as a result of environmental regulations and increasing demand within New York State. The New York Power Authority (NYPA) has recently retired one unit within Con Edison’s gas territory – NYPA Poletti. As mentioned previously, NYISO does not forecast the need for new in-city generation over the next 10 years. However, the current owner of the Indian Point facility, Entergy, is facing a re-licensing process and a potential need to install cooling towers to meet environmental rules. The Company is monitoring as a signpost the re-licensing status of the facility and the potential for Entergy not being able to renew the operating licenses of the Indian Point Units 2 and 3, which would result in their retirement at the end of September 2013 and December 2015, respectively. The facility is a major source of supply of electricity for Westchester County and New York City.

Our projections of gas needs for electric generation within our territory are based on the continued need for in-city generation to meet electric demand growth as electric transmission into NYC is limited. This is consistent with the projected electric supply mix in Con Edison’s Electric System Long Range Plan (ELRP).

- Plan case: is consistent with the ELRP plan case and projects gas usage for electric demand to grow at a little over 2% Compound Annual Growth Rate (CAGR)
- Low case: is consistent with our ELRP low case and projects gas usage for electric demand to grow at less than 0.5% Compound Annual Growth Rate (CAGR)
- High case: is consistent with our ELRP high case and projects gas usage for electric demand to grow at between 3.5-4% Compound Annual Growth Rate (CAGR)

With the current consideration of phasing out of the use of heavy fuel oil for heating within NYC, we believe in-city generators may be subject to increasing pressure during the planning period to reduce or eliminate use of #6 oil for generation. Of the in-city generation (with the retirement of the Poletti unit), nine units with a total capacity of 3,277
MW are fueled by #6 oil with natural gas back-up. Because all nine units are already capable of burning natural gas, the units can readily use natural gas as the primary fuel.

The following meetings were held to-date with external stakeholders to communicate the information and progress of the GLRP:

- NYC Energy Policy Task Force – 1/28/10
- NYS DPS Staff:
  - 2/10/10 – Video conference with DPS staff to review GLRP status
  - 3/9/10 – Video conference with DPS staff to review GLRP status
  - 6/2/10 – Presentation in Albany
  - 7/1/10 – Discussion to clarify comments received from Staff on GLRP
  - 7/23/10 - Follow up discussion on answers provided to their comments
  - 9/7/2010 – Reviewed both gas and steam long range plans with a PSC Commissioner

Since NYISO does not forecast the need for new, in-city generation over the next 10 years, there is no need for additional gas transmission system reinforcement. Any additional gas usage due to increased demand would be provided on an interruptible basis utilizing existing facilities. Con Edison is not responsible for the capital cost associated with reinforcement associated with interruptible customers. As a result, a cost benefit analysis based on reinforcing the gas transmission system for electric generation revealed that no savings to Con Edison would be realized.
Recommendation 38:
Identify a Steam Master Plan and incorporate within it a greater emphasis on what is happening on and to its distribution system. (Conclusion 4)
Team Lead(s): Vic Mullin / Saumil Shukla

Summary of Implementation Actions:

This recommendation is complete.

The Liberty Audit report identified the need to develop a “Steam Master Plan” with an emphasis on the distribution system. The Company expanded the scope and developed a “Steam Long Range Plan” (SLRP) to identify and understand the issues and challenges impacting the steam system over the long-term, and develop a long range business strategy to maintain the viability and sustainability of the Steam business. The goal of the Plan is to help direct the Company in balancing supply capacity with anticipated customer demand, while maintaining the competitive value of steam for the steam customer.

A cross functional team was established which developed the scope of work, determined how the SLRP would interface with the Gas and Electric Long Range Plans and wrote the 20-year plan.

The SLRP addresses the business strategy for the Steam system for the next 20 years as well as the future investments on production and distribution, while recognizing that customers play a critical role in driving the requirements. As part of the development of the SLRP, the transmission and distribution systems were evaluated and initiatives were developed with the purpose of addressing system needs, deferring or minimizing the investment requirements on the system, increasing asset utilization, and improving overall performance. Long term programs for maintenance and operations, including renewal, removal or addition of assets, were developed. Major distribution investments the Company will undertake to meet the Plan are as follows:

- Continue expansion of existing remote monitoring program in flood prone locations and trap monitoring.
- Extend distribution system monitoring and Research and Development (R&D) initiatives on water hammer to continue enhancing employee and public safety.
- Implement a smart-grid approach for Steam that includes additional monitoring of the network and the expansion of advanced metering to allow for demand response (DR) programs. This would also provide better customer usage data which may be used to improve conservation program efforts and load shedding capability.
- Establish an asset renewal program aimed at replacing anchors, valves, manhole covers and other critical pieces of the distribution system.
- Increase operational efficiency by incorporating benefits from smart grid, asset renewal, R&D and other initiatives into process improvements and workforce management.

The Company developed three demand forecast scenarios representing the high, low, and plan cases. Each forecast scenario considers historical customer growth and departure patterns related to building renovations and new construction; the possibility of additional load from oil to steam conversions driven by potential regulatory changes; load loss from the growth in customer sited and government incented combined heat and power (CHP) projects; and the influence on demand and sales of customer implemented energy efficiency measures. Under the Plan case, aggregate customer load is projected to be relatively flat over the 20 year period. The Plan case accepted a level of maturity in the steam service market territory in terms of growth potential and efficiency improvement impact.

During the development of the Steam Long Range Plan, the Company met with a representative group of stakeholders, the New York Department of Public Service Staff, and the New York Energy Policy Task Force. In the future, the Company will continue to have discussions with key stakeholders about our plans. Current customer feedback was considered and incorporated in the Plan.

Under the Plan case, the customer’s total steam energy bill over 20 years, including projections for fuel and taxes, is expected to grow, in real dollars, at an approximate average compound annual growth rate (CAGR) of +0.7% annually. By incorporating the SLRP initiatives for improvements in customer energy efficiency and demand, the Company will be able to better manage the system and thereby defer future large scale capital investments, optimize the current assets and minimize bill impact. The Plan Case is estimated to yield annual savings of $20 million from operating expense reductions and $22 million savings from fuel switching in gas addition projects based on the various assumptions used in the case. An important factor to this projected outcome is the implementation of Con Edison recommended initiatives, to change regulatory and tariff provisions, which were drafted in the Steam Long Range Plan. A review of the initiatives has begun in a Collaborative fashion with representatives from the Public Service Commission (PSC), New York City, Westchester County, New York Energy Consumers Council (NYECC) and Consumer Power Advocates (CPA).

**Supplemental Completion Update:**

On December 8, 2011 the Company submitted to Staff the final version of three studies that examined the following:
1. Assessment of Customers with Limited Alternatives to Steam that will be Supplied Primarily by Cogeneration
2. Assessment of Transferring the Equivalent Load of Con Edison’s Boiler-Only Steam Capacity to Customer Sited Boilers and CHP
3. Assessment of the 40-Year Phase Out of the Steam System

These detailed documents and their associated worksheets confirmed that the Company’s Steam Long Range plan is viable. The studies have been reviewed in detail with the PSC Staff.
**Recommendation Number:** 74

Staff a project coordination/specialist group under the Chief Distribution Engineer to assist in the execution of distribution capital projects, such as Main Replacement Program (Conclusion #1).

**Team Lead(s):** Frank Ciminiello

**Summary of Implementation Actions:**

This recommendation is complete.

Based on the benchmarking studies and the identification of potential benefits that could be realized, Gas Engineering created a new section consisting of one program manager and four project engineers under the Chief Gas Distribution Engineer effective January 1, 2010. Each project engineer will support the small distribution projects for a specific operating area. The new section comprised of project engineers under the Chief Gas Distribution Engineer was internally sourced from the current pool of employees in Gas Engineering. This approach helped avoid an increase in the headcount to the Gas organization. The organization absorbed the loss of manpower through shifting roles and responsibilities, increasing responsibilities for current employees and achieving various synergies through having a separate field engineering group.

Implementation is expected to improve cost control and program schedule accountability. This equates to an efficiency improvement of $700,000 on the total spending level for the replacement of leak-prone pipe if we achieve a 1% productivity improvement. The cost for implementing the program (software, training, and certification) is $25,000.
Recommendation Number:  75
Improve and expand the current project scope documentation to add sections on risks and rewards and alternative methods. (Conclusion 2)
Team Lead(s):  Frank Ciminiello

Summary of Implementation Actions:

This recommendation is complete.

In 2009 Con Edison’s Cost Management Group, formerly the Central Planning and Analysis group, established a capital project documentation template for use by all operating organizations in the preparation of the annual capital budget. The information developed for this new template includes: work description, justification, alternatives, risk of no action, summary of financial benefits and costs, non-financial benefits, technical evaluation/analysis, sensitivity analysis, project relationships, estimated completion date, current working estimate, and funding. Gas Operations has integrated this template into its 2010 Capital Budget Book prepared in 2009. This template implements the enhancements presented in Recommendation No. 75 (“Expand the current project scope documentation to add sections on risks and rewards and alternative methods.”) Electric Operations and Steam Operations also use the new template for capital budget preparation. Previously, Gas Engineering used a project scope document which contained sections for the work description, justification, start date, planning and budgeting, status, constraints and stakeholders affected.
**Recommendation Number:** 76

Start benchmarking with other urban utilities and utilize what these other utilities are doing better to improve the CECONY program and project management of capital projects.

(Conclusion 3)

**Team Lead(s):** Frank Ciminiello

**Summary of Implementation Actions:**

This recommendation is complete.

Gas Engineering conducted telephone interviews of eight utilities using a list of questions to guide the interviews. The questions focused around the organization structure, methods of project selection, planning, execution, monitoring and control, closing and measures of project. Additionally, Gas Engineering examined project management practices at two oil companies given their experience with large projects. Further, the Project Management Body of Knowledge (PMBOK) published by the Project Management Institute was also researched. The details and results of the benchmarking study were provided to PSC staff as part of the completion process.

The benchmarking study revealed that our project management practices generally conform to industry best practices. Specifically, taking a phased approach to projects is consistent with our corporate instruction that recommends creating Conceptual Packages for projects greater than $15M. CI-291-2 (Project Management Process) states "Once the need for a project has been identified, it is recommended that a Conceptual Package be developed. It is preferred that projects submitted for the following year’s budget process be based on estimates from the Conceptual Packages."

As a result of this benchmarking effort, Gas Operations will follow our corporate instruction recommendation on preparation of Conceptual Packages.

The cost of performing the benchmarking study was minimal since the effort was conducted over the phone. The benchmarking concluded that the industry best practices on taking a phased approach to our projects is consistent with our corporate instruction. Specifically, the recommendation is to do Conceptual Packages prior to budgeting and prior to detailed design. There is no incremental cost to doing conceptual packages per this recommendation since the elements of a conceptual package (including an approved scoping document, general arrangement drawings, equipment list, and cost estimate) are currently done for all projects. This recommendation is related to the timing of when the conceptual package is completed.

Conceptual Packages done up front should result in fewer design and construction changes, thereby providing a cost avoidance due to project changes in the detailed engineering phase of the project or in construction. It should also assure that an appropriate cost estimate is used for project budgeting purposes.
Additionally, consistent with benchmarking study results, a new group was formed to apply project management principles on smaller projects, such as schedule and cost management through Current Working Estimates (CWEs), to Gas distribution programs (see implementation of recommendation 74).

These actions represent a more comprehensive application of project management principles to our projects and programs.
**Recommendation Number:  77**  
Identify projects requiring the application of project management techniques through a more formal, structured process. (Conclusion 1)  
Team Lead(s):  Saumil Shukla

**Summary of Implementation Actions:**

This recommendation is complete.

Steam Procedure S -11959 – Work Management has been revised and re-issued on March 15, 2010 to include a section on Project Management. The project management procedures and processes defined in Central Operations Procedure 10-0-5 – Project Management will be applied to projects meeting the following criteria:

- non-routine, discrete projects that have a definite time duration, and
- have an estimated cost of greater than or equal to $500,000, and
- requires the support of engineering and/or multiple organizations, or
- at the discretion of the General Manager (GM) Steam Distribution

The benefit of this implementation is the development of a more formal, structured process for project management in Steam Operations, particularly in Steam Distribution. Increased focus on project management can positively impact schedule, quality, and cost management as well as general oversight of projects. The cost of implementation is nominal as existing resources were used. There were no additional resources added for project management.

Savings are expected from overall improved planning, scheduling and cost control for the major projects where these techniques would apply. For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that that there will be 1% savings for efficiency improvements associated with project management techniques. The estimated savings is in the order of $30,000 per year, which will exceed the cost of implementation.
**Recommendation Number:** 78

Train steam distribution operations personnel in work and project management techniques.

(Conclusion 3)

Team Lead(s): Saumil Shukla

**Summary of Implementation Actions:**

This recommendation is complete.

All appropriate employees have completed the identified project management training as of March 15, 2010. The training included the Project Management Process eLearning course (SBS0071), the 3-day Project Planning and Control course (LDM0200), and the 5-day Advanced Topics in Project Management course.

The benefit of this implementation is the expansion of formal project management training for those individuals in Steam Operations responsible for project management, particularly Steam Distribution. Training the individuals will allow them to utilize these skills in the management of projects which should have a positive impact on cost, schedule and quality. The cost associated with training of employees was $3,500. Formal training will ensure consistency and priority for this initiative.

The benefits from this training include overall improved planning, scheduling and cost control for the major projects where these techniques would apply. For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that there will be 1% savings for efficiency improvements associated with project management techniques. The estimated savings is in the order of $30,000 per year.

As a result of this training, the Company expects savings to exceed the cost of the aforementioned project management training.
Team 12 – Energy Supply
Executive Sponsor: Luther Tai

Recommendations: 83, 84, 85, 88, 89, 90, 91, and 92

Recommendation Number: 83
Internal Auditing should schedule more frequent audits of electric procurement decisions, documentation for entering into electric supply contracts, and daily purchase decisions.
(Conclusion 17)
Team Lead(s): Lou Bevilacqua

Summary of Implementation Actions:

This recommendation is complete.

The 2010 Audit Plan approved by the Board contains the broad and comprehensive program of internal audits to ensure compliance with internal controls governing the operations of Con Edison. The 2010 Audit Plan allocates 2,300 hours to Energy Management related functions. In 2009, the Plan allocated 1,500 hours.

The hours were allocated as follows:

- 1,000 hours have been added to the 2010 audit plan to conduct regular audits of functions related to Electricity Procurement (500 hours) and Gas Procurement (500 hours). The audits will include reviews of compliance with corporate policies and procedures associated with procurement decisions and the documentation required for entering into electric supply contracts.

- In addition, the Company conducts annual SOX controls audits as part of its SOX Controls Testing Plan required under Section 404 of the Sarbanes-Oxley Act (SOX) of 2002. In 2010 we will be testing 55 controls and have allocated 900 man-hours of audit time related to Electricity and Gas Procurement. These controls will be in the broad areas of accounting, hedge accounting, confirmations, credit risk, deal authorization and capture, fuel procurement and inventory, gas supply and purchased power, portfolio valuation and reporting and risk management. A detailed listing of these controls can be seen in the attached SOX controls catalogue. In 2009 we tested the same 55 SOX controls related to energy procurement and also utilized 900 audit hours. The Energy Management SOX controls catalog contains 156 controls. For those controls that are not tested annually in SOX, the Company has devised a rotational controls testing plan which subjects these controls to tests over a seven-year period. In 2010, 13 controls (400 hours) relating to Energy Management-Hedge Accounting will be tested under this plan. In 2009, 29 controls (600 hours) were tested which dealt with gas supply and purchased power, risk
management, and portfolio valuation and reporting. As these additional SOX controls are tested on a rotational basis by functional area, the number of controls and hours allocated can fluctuate from year to year.

At CECONY, in 2008 we spent $3.5 billion for the procurement of electric energy. By increasing the amount of review of these procurements in the annual plan we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place. In 2010, we are incorporating this recommendation into our audit plan to further reduce the risk of overpayment or misappropriation of resources, and promote compliance with controls and procedures as a result of the audits.
**Recommendation Number:** 84

Document processes, procedures, and guidelines for electric supply and scheduling, and for the 20 percent purchase flexibility in electric hedging. (Conclusion 20)

**Team Lead(s):** Joe Oates

**Summary of Implementation Actions:**

This recommendation is complete.

Prior to 2009, the electricity hedging strategy and plan allowed for 20 percent flexibility in electricity hedging. Each year, Energy Management submits the three-year financial electric hedge plan to the Board for approval of the strategy for the upcoming period. In 2009, as a result of the annual update to the electricity hedging strategy and plan, Energy Management eliminated the 20 percent flexibility in electricity hedging to provide better control of the hedging process and a more structured process for implementing hedges and this was approved by the Board on April 16, 2009. The Vice President of Energy Management approves the hedge target implementation each year which is monitored by Energy Risk Management to ensure compliance with the procurement schedule.

The Electricity Supply and Scheduling group has created a Physical Electricity Scheduling Manual and 12 process guides for the purchasing and scheduling of electricity to document the processes, procedures and guidelines followed in the department’s daily operations. These documents will ensure more consistency within the group and improve knowledge transfer.
Recommendation Number: 85
Make finding means for increasing interdepartmental coordination an Energy Management priority. (Conclusion 3)
Team Lead(s): Joe Oates

Summary of Implementation Actions:

This recommendation is complete.

The Electricity Supply and Gas Supply departments scheduled regular meetings between the respective hedging, scheduling, and billing sections to investigate opportunities to improve coordination between the departments. Additionally, an off-site planning meeting was held with the Directors and Section Managers from both departments in attendance to evaluate current practices and identify best practices, information sharing and coordination, and possible efficiency gains.

The primary action identified was to incorporate regularly scheduled meetings between each of the sections in the departments - the scheduling sections meet daily, the hedging sections meet weekly, and the billing sections meet monthly - to continuously evaluate areas for improvement, review market information, and exchange ideas and best practices. Some of the current opportunities being investigated include:

- Transferring responsibility for hedging gas purchases for Steam Operations to the electric hedging group
- Exploring the possibility of transfer pricing for natural gas Zone 6 basis to allow electric hedging to purchase directly from gas hedging
- Investigating feasibility of using dispatch rights provided in the electric contracts to meet firm gas customer peak day requirements
- Exploring areas for alignment of processes in the billing groups to provide consistency

The meeting schedules for each of the different sections have been incorporated in process guides or manuals in Energy Management to ensure that the groups meet consistently.

The results of reviewing the hedging groups’ activities have shown that some of the specific activities associated with the hedging functions are similar, such as adherence to hedging plans and entry of financial transactions into Allegro system of record, but a substantial number of the tasks and knowledge base required to perform the functions in electric or gas are separate and distinct. To the extent that the results of the ongoing meetings and subsequent implementation of coordination improvements between the two groups results in hedging benefits or improvements, those reduced costs will be directly passed on to customers as they occur.
Recommendation Number:  88
Expand Gas Supply’s range of potential capacity alternatives as it considers firm customers’ peak-day requirements for supply. (Conclusions 14, 15)
Team Lead(s):   Joe Oates

Summary of Implementation Actions:

This recommendation is complete.

Gas Purchasing and Scheduling (GP&S) considers pipeline capacity connected directly to one of the CECONY city gates and under contract to CECONY, city-gate call options, and buying from customers that have their own gas-supply arrangements as alternative ways to meet peak-day requirements for supply.

The GP&S and the Electricity Supply groups have reviewed existing Power Purchase Agreements (PPAs) to determine the feasibility of using dispatch rights provided in the electric contracts to schedule down electricity purchases, thereby freeing up city-gate delivered capacity that could be used to meet firm gas customer peak day requirements. Based on our review of existing PPAs, we have identified a potential candidate. The feasibility of such an arrangement is currently undergoing a legal and regulatory review.

In addition, through a Request-for-Proposals (RFP) process, the Company continues to pursue “city-gate” call options with market participants, including fuel managers that manage the assets of generators operating behind the Company’s city-gate. The Company has entered into agreements with these suppliers for “city-gate” call options over the past several years.

Every winter, GP&S distributes an RFP to potential suppliers, soliciting offers for peaking supplies. The offers are evaluated and the least-cost supplies are selected based on established guidelines. Any cost benefits realized through these peaking supply arrangements would be passed along to the firm gas customers through the Monthly Gas Cost Factor.
**Recommendation Number:**  89
Conduct occasional Gas Supply tests to identify potential additional types of supply arrangements. (Conclusion 17)
Team Lead(s):  Joe Oates

This recommendation is complete.

Gas Purchasing invites suppliers participating in Request for Proposals to submit alternate supply proposals. A Gas Supply Operating Guideline was updated to state that Gas Purchasing will affirmatively request alternate supply proposals during the RFP Process. In addition, Gas Purchasing will evaluate unsolicited proposals and determine the feasibility of executing a transaction outside the RFP process or a formal solicitation.

These new supply points expand the range of suppliers that can participate in the Company’s natural gas procurement activities. Any reductions in cost associated with new supply arrangements will be passed on to customers through the gas adjustment clause.
Recommendation Number:  90
Keep financial and credit information for gas supplier’s current. (Conclusion 20)
Team Lead(s):  Joe Oates

Summary of Implementation Actions:

This recommendation is complete.

Gas Supply has updated its procurement guidelines to include a provision that they will request current credit information from the Energy Risk Management – Utilities department for all active counterparties invited to respond to Requests-for-Proposal (RFP). This guideline ensures that all counterparties, including those for physical transactions, are evaluated utilizing the most current credit rating for consideration of their creditworthiness. The Gas Supply operating document guideline was updated on September 30, 2009 and reflects this process. It is a new operating guideline, and is a revision of its predecessor, which did not include the RFP process. The new guideline has been shared with the PSC.

The Energy Risk Management – Utilities department updates the Allegro energy risk management system with all active counterparty credit ratings, and any changes to credit ratings. The Company’s Risk Procedure provides the guidance for this process and has been shared with the PSC.
Recommendation Number: 91
Find specific, objective ways for Gas Supply to evaluate its own performance. (Conclusion 27)
Team Lead(s): Joseph Oates

Summary of Implementation Actions:

This recommendation is complete.

Gas Supply has taken a variety of steps that will provide ongoing opportunities for self-assessment and promote the identification and implementation of performance-enhancing measures. These include ongoing collaboration with counterparts in Electricity Supply and the addition of new trading counterparties, inviting suppliers to make unsolicited proposals (described in the response to Recommendation 89), and participation in regional LDC activities sponsored by the Northeast Gas Association, attendance at the Northeast LDC forum, and other venues.

Recent improvements resulting from Gas Supply’s self assessment activities include the use of on-line auctions, adding new counterparties for supply procurement, entering into Asset Management Arrangements with third parties to manage gas supply assets, and measures to improve gas cost accrual accuracy. These improvements have the potential to lower gas cost, extract additional value from the Company’s supply contracts, and improve the accuracy of the work. While we expect savings to result, it is difficult to estimate the magnitude. To the extent savings are realized, they will be passed on to customers.
Recommendation Number: 92
Solicit proposals for external asset management. (Conclusions 28, 30)
Team Lead(s): Joe Oates

Summary of Implementation Actions:

This recommendation is complete.

In its audit, Liberty recommended that the Company adopt a process for expanding the use of Asset Management Arrangement (AMAs). This included making a presentation to interested and qualified asset managers on the operation of our transmission and distribution systems and retail choice program and soliciting submissions of conceptual proposals by interested parties. Liberty recommended that the Company then proceed with a formal competition and indicate the types of arrangements it was considering and the evaluation criteria it would use for making a selection. In addition, Liberty suggested that the results of the process be summarized in a report to Department of Public Service (DPS) staff.

In order to better optimize the joint CECONY and O&R gas supply portfolio, the Company has entered into AMAs for Canadian pipeline capacity and gas supply since 2006 and for U.S. gas supply and pipeline and storage capacity since 2009. These transactions followed the issuance of Federal Energy Regulatory Commission (FERC) Order 712, which clarified capacity release and shipper-must-have-title rules under AMAs for gas supply and pipeline and/or storage capacity.

During 2009, the Company worked to expand its understanding of AMA structures and FERC rules by meeting with counterparties regarding the following: supply/capacity management AMAs, a winter delivered service using a path on pipelines and storage not released to retail-choice suppliers, credit for unrated entities, taxes associated with AMA storage inventories, and how commodity pricing and AMA payments to the Company would be applied.

The Gas Purchasing and Scheduling Section, which has execution responsibility for AMAs, has held meetings with various Company groups to review various AMA issues, e.g., the Energy Risk Management Department regarding credit, the Gas Hedging and Analysis Section regarding the evaluation of assets, the Gas Billing and Analysis Section and Information Resources Department regarding recording and accounting for these transactions, and the Law Department on executing the transaction confirmations.

In 2009 and 2010 the Company executed a total of six AMAs, largely through Request for Proposal processes. These AMAs were structured to provide summer storage fill, summer fill and winter delivery, supply/capacity management. As a result, gas supply costs in customer bills will be reduced by an estimated $2.3 million.
By entering into AMAs with third parties to manage gas supply assets, the Company gets the opportunity to extract additional value for the assets. The Company manages the risks of AMA transactions (e.g., a counterparty’s failure to perform), by using NAESB agreements, which include provisions regarding performance failure. In addition, supplemental language is included in the transaction confirmation and the asset manager is required to provide performance assurance against its failure to perform. Revenue received from the AMAs will reduce gas costs for customers as those benefits flow through the gas adjustment clause.
### Appendix D: Cost Benefit Summary for Recommendations

<table>
<thead>
<tr>
<th>Team</th>
<th>CE No.</th>
<th>Recommendation (w/referenced conclusions)</th>
<th>Implementation Costs and/or Annual Operating Costs</th>
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<td>1. Electric Long Range Plan</td>
<td>1</td>
<td>Improve the planning process. (Conclusions 1, 2, 3, 4, 5)</td>
<td>Implementation Savings, Benefits and/or Future Cost Avoidance</td>
<td>The main benefits are greater alignment of objectives and goals across business units, and stronger linkage of short-term to longer-term strategies. The business planning process provides detailed work plans that are designed to achieve the goals and strategic objectives and adherence with the Company’s cost management initiatives. Work plans must demonstrate that the appropriate work has been proposed for the forecast period, with particular attention paid to next budget year’s activity. Capital and operating projects and programs will be judged based on their alignment with the Company’s strategic priorities (the resource optimization process) so that funds are allocated efficiently to manage risks and meet strategic objectives.</td>
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<td>2</td>
<td>Take the ERM process associated with operating risks to the next level. (Conclusion 7)</td>
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<td>With the implementation of Departmental Risk Profiles and new risk management system (CURA), there is a more focused monitoring of risk mitigation activities for key corporate and departmental risks of the Company. While exact dollar savings cannot be quantified, periodic risk assessments are better aligned with the Company’s budget and planning processes. Over time, classification of risks by mitigation status and continuous monitoring of Key Risk Indicators will improve strategic allocation of resources based on available risk information.</td>
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<td>3</td>
<td>Define the role of the Strategic Planning Unit. (Conclusion 6)</td>
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<td>4</td>
<td>Revisit the subjects investigated by the interdisciplinary teams. (Conclusion 6)</td>
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<td>5</td>
<td>Develop a comprehensive vision and 20-year master plan for the electric system. (Conclusion 8, 9)</td>
<td>Cost to date: $2.2 Million (Including internal and external labor). Through the efforts of this long range planning process, we have been able to identify $3.1 Billion in estimated savings and avoided capital investment over the 20 year horizon.</td>
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<td>21</td>
<td>Aggressively move forward with the major study planned by Market Research on efficiency potentials and include a special focus on efficiencies that can be targeted to specific networks. (Conclusion 28)</td>
<td>The cost of the energy efficiency study was $825,000 and was funded in Case 07-E-0523 for the 2008 – 2009 rate year. The major benefit of these studies is that we receive intelligence around the DSM opportunities. To the extent these opportunities materialize, the need for capital infrastructure spending is reduced.</td>
<td>Demand side management (demand response and energy efficiency) may defer or eliminate the need for expensive capital infrastructure, while at the same time reducing green house gas (GHG) emissions and enhancing reliability. All energy efficiency programs are subject to a Total Resource Cost test and the study helps us design better programs and address barriers to demand side management.</td>
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### 2011 Costs, Savings, Benefits, and/or Future Cost Avoidance

- **Range Plan**
  - Electric Long Range Plan: **$2.4 billion** in net electric savings and avoided capital investment over the 20 year planning horizon. This is an addition to the $3.1 billion identified in the 2010 plan.
  - Total electric savings identified in the ILRP are **$4.2 billion** over 20 years, which are partially offset by **$1.8 billion** of capital needed to meet additional demand during this timeframe.

### 2012 Costs, Savings, Benefits, and/or Future Cost Avoidance

- Through the efforts of the Integrated Long Range Plan we have identified **$2.4 billion** in net electric savings and avoided capital investment over the 20 year planning horizon. This is an addition to the **$3.1 billion** identified in the 2010 plan.
- Total electric savings identified in the ILRP are **$4.2 billion** over 20 years, which are partially offset by **$1.8 billion** of capital needed to meet additional demand during this timeframe.

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<td>22</td>
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<td>Evaluate options to enable the consideration of current and future load curtailment initiatives, both at CECONY and NYISO, for dependable network demand reduction. (Conclusion 29)</td>
<td>Proposed pilot program cost is $22 million. Projected benefits of reducing energy consumption and demand, reducing environmental impact; and a reduction of capital infrastructure required to meet customer needs.</td>
<td>Total costs for all Peak Load Shaving Programs during the 2010 program year were $985,000 or approximately 4% of the projected two year costs of $22 million. These costs are reflective of program start-up and low participation, but should increase as the program matures over the next few years. The peak load shaving programs are not mature, and had limited customer enrollment. As a result, there is not enough current information to evaluate whether the programs are either cost or operationally (from the utility perspective) effective. The pilots are currently expected to run through the end of 2012 and at that time we will have a better understanding of the potential for all peak shaving programs. However, we will continue to evaluate each pilot and program on an annual basis and adapt the programs as appropriate.</td>
<td>We continue to evaluate each pilot and program on an annual basis and adapt the programs as appropriate. Our program costs are analyzed at the end of each summer capability period, which runs from May 1 through October 31. As a Public Service Commission requirement we provide an annual evaluation of demand response program performance, including costs, to the Commission by December 1 of each year.</td>
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<td>34</td>
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<td>Establish a base level of network reliability for new networks. (Conclusion 24)</td>
<td>No incremental cost. Establishing a base level of network reliability allows Con Edison to identify the networks on which reliability funds should be targeted in order to provide an overall system improvement. In order to provide for system improvement but keep costs down, the Company has identified a number of programs which will address network deficiencies and increase network reliability. The effectiveness of each program on a specific network is evaluated in order to determine the effects of reliability spending. The most cost-beneficial solution that meets the reliability goal is selected.</td>
<td>Guided by specific network cost benefit relationships, the optimal allocation of the related capital budget is continuing along anticipated lines. The risk of network shutdown has been reduced by 32% while effectively maintaining existing risk levels for the remaining networks. Additional reductions will be realized throughout the remainder of 2011. Also see recommendation 24 for associated benefit.</td>
<td>Since the date of the close-out summary, the risk of network shutdown was reduced by 51% for the top 20 highest risk networks while effectively maintaining existing acceptable risk levels for the remaining networks. The company is on target to attain the base level of network reliability by the end of 2015. See Recommendation 24 for associated benefits.</td>
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<td>39</td>
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<td>Strongly link CECONY’s long-term electric plan with annual budgets, rate plans and 5-year capital plans. (Conclusion 4)</td>
<td>Costs included under recommendation 5. Benefits included under recommendation 5.</td>
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<td>42</td>
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<td>Prioritize CECONY capital projects and allocate funding using long-term economic analysis metrics as a significant decision factor. (Conclusion 8)</td>
<td>Costs included under recommendation 5. Benefits included under recommendation 5.</td>
<td>Costs included under recommendation 5. Benefits included under recommendation 5.</td>
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<td>2 Board Leadership</td>
<td>6</td>
<td>Revise Board Committee Structure to better coordinate functions and to focus on infrastructure planning, oversight, and performance measurement. (Conclusions 1 and 8)</td>
<td>Implementation costs consist of the fees to be paid for additional meetings and the time spent by management and the Board members in developing the calendar and Committee dashboards and reviewing materials. The cost of additional Board and Committee meetings is approximately $30,000. The benefit is expected to be enhanced Board engagement and oversight. The revised board and committee structure, and the revised calendar will allow the committees, as appropriate, to enhance their focus on</td>
<td>Implementation costs were minimal as this is a recalibration of functions related to the duties and responsibilities of the respective committees. The cost of performing the charter review and developing the dashboards was also minimal. The benefit is expected to be enhanced Board engagement and oversight. The revised Board and committee structure, and the revised calendar will allow the committees, as appropriate, to enhance oversight of management’s infrastructure planning and performance management.</td>
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<td>7</td>
<td>Continue efforts to identify board candidates with energy utility experience. (Conclusion 2)</td>
<td>No incremental cost. The Company believes that the recommendation would contribute to the Company’s success in the goal of maintaining a competent and qualified board. A well-qualified, informed and engaged Board is a key to the effective oversight of a corporation like Con Edison. The Board assesses its performance as part of the self-assessment process, and stockholders perform an assessment when they are requested to vote for directors at the annual stockholders meeting.</td>
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<td>8</td>
<td>Incorporate changes in management’s form and schedule for infrastructure planning and budgeting into a more structured, resequenced, and more intensive regimen of board review. (Conclusions 5 and 6)</td>
<td>Costs included under recommendation 6. The Board and Committee calendar has been revised, after consultation with the Board and the relevant committees, to allow for a more structured review of short and long-range system needs in advance of annual budgeting, and provides for planning and budget review by the committees and the Board. This revised calendar promotes enhanced Board oversight of planning, budgeting, and operations.</td>
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<td>43</td>
<td>Require changes in capital projects and programs of more than 20 percent from the annual budget to be approved by the board of trustees. (Conclusion 6)</td>
<td>No incremental cost. Recommendation under review.</td>
<td>The benefit is expected to be enhanced Board and Finance Committee engagement and oversight. The Delegation amendment will provide enhanced Board and Finance Committee oversight over certain capital projects.</td>
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<td>56</td>
<td>Review the roles of management, the Board and/or its committees after serious events such as the 2008 electrical fatalities. (Conclusion 6)</td>
<td>No incremental cost. The Company incorporated the Audit recommendation and is providing the Board with enhanced information pertaining to incidents and more follow-up information concerning the process changes implemented as a result of the incident. This enhanced information facilitates the Board’s understanding and discussion of the incident and the impact of the process change.</td>
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<td>3 Rate &amp; Financial Strategy</td>
<td>41</td>
<td>Work toward the re-establishment of multi-year electric rate cases. (Conclusion 3)</td>
<td>No incremental cost. On average, incremental non-staffing costs associated with electric rate case filings are between $1.2 and $1.6 million. The main components of these costs are for consultants and expert witnesses, public notice ads, travel expenses, and printing. Some of these costs (at least 20%), plus some staff positions, may be avoided in the longer term, to the extent that multi-year rate plans become the norm and the number of interim proceeding and collaboratives are not significant.</td>
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<td>4 Work Management</td>
<td>32</td>
<td>Place all distribution tree trimming under a central corporate management function with accountability to corporate management. (Conclusion 22)</td>
<td>At year end 2010, we experienced savings of approximately $350,000 over the 2009 (pre-centralization) tree trimming contractor costs. Through six months of 2011, we have experienced savings of approximately $175,000 over the 2009 tree trimming contractor costs.</td>
<td>We continue to see improvements in our tree trimming contractor costs since the consolidation of the program under one organization, the gross unit cost in 2009 was approximately $5,080/mile and in 2011 it was approximately $4,960/mile.</td>
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<td>33</td>
<td>Strengthen the distribution vegetation management inspection program with accountability. (Conclusion 23)</td>
<td>Cost included under recommendations 40 and 72. Feedback loops will provide opportunities to evaluate and adjust projects and programs to ensure the appropriate balance of cost and value. An annual review of the capital optimization portfolio will result in improved capital allocation decisions to achieve maximum value for total work. The benefits are accounted for under recommendations 24, 72 and 40.</td>
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<td>44</td>
<td>Establish formal informational feedback loops for project analysis and project prioritization. (Conclusion 27)</td>
<td>Cost included under recommendations 40 and 72. Feedback loops will provide opportunities to evaluate and adjust projects and programs to ensure the appropriate balance of cost and value. An annual review of the capital optimization portfolio will result in improved capital allocation decisions to achieve maximum value for total work. The benefits are accounted for under recommendations 24, 72 and 40.</td>
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<td>51</td>
<td>Establish fleet size criteria based on historical data on total vehicle usage hours versus total physical work performed in hours in the region for each vehicle class. (Conclusion 6)</td>
<td>To date, over 200 vehicles were identified and removed from service or redeployed in lieu of purchases. In net terms, reductions have saved approximately $341,000 in avoided maintenance costs and reduced the capital investment (replacement value) of the fleet by $13.6 million.</td>
<td>In 2012, 181 vehicles were identified and removed from service or redeployed in lieu of purchases. In net terms, reductions have saved approximately $180,000 in avoided maintenance costs and reduced the capital investment (replacement value) of the fleet by approximately $12.1 million.</td>
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<td>67</td>
<td>Perform analysis on work items with unacceptable QA rejection rates to isolate performance problems. (Conclusion 5)</td>
<td>QA performance has continued to steadily improve. In 2008, 2009, and 2010 compliance with the inspection and construction metrics were, 81%, 92% and 93% respectively. We are on track to achieve the 2011 year end goal of 92% compliance with the inspection and construction metrics.</td>
<td>QA performance has continued to steadily improve. In 2011 compliance with the inspection and construction metrics was 95%. We are on track to achieve the 2012 year end goal of 96% compliance with the inspection and construction metrics.</td>
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<td>71</td>
<td>Implement a work management system in Electric Operations. (Conclusion 1, 4, 5, 16)</td>
<td>The total cost of this project is estimated to be between $138 million and $174 million. The capital costs range between $119 million and $155 million; O&amp;M costs account for $19 million. The total annual savings, which will be realized upon full implementation in 2014 is between $45 million and $48 million.</td>
<td>In 2011, actual project costs were $25.4 million versus a budget of $35.2 million; the current working estimate for year end 2012 is $30.8 million versus a budget of $39.8 million. Total annual savings of $45.1 million net of ongoing information technology maintenance expenses will be realized upon full implementation in 2014.</td>
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<td>Design and implement written project and program management procedures and expectations, including definitions of roles, responsibilities and expectations, cost control plans, and scope control procedures. (Conclusion 2, 7, 9, 13, 14, 15, 18)</td>
<td>Implementation and annual operating costs for the program staffing, software, certification and training) are $1.3 million. Benefits which could be gained by formalizing the project management function include improved ownership/accountability of projects at a manageable level, improved focus on financial/schedule, better long-term planning, and improved knowledge transfer. This equates to a potential efficiency improvement of $8.1 million on the total capital spending level if we achieve a 1% productivity improvement.</td>
<td>Costs and benefits estimates have remained the same since our last update. We expect an annual productivity improvement of 1% on the total Electric Operations spending level. Net of annual operating costs, savings are estimated $6 million annually.</td>
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<td>Three new project managers and nine staff members have been hired into the Electric Operations Project Management Organization. They are responsible for schedule, cost, and quality performance for various projects and programs across the Manhattan, Bronx/Westchester and Brooklyn/Queens regions. This group has expanded from our original staffing level estimate of eight to twelve individuals. As a result, annual operating costs are $1.9 million. Annual productivity improvements of 1% on the total Electric Operations capital spending level is expected, resulting in savings of $8.1 million annually. Net of annual operating costs, savings are $6.2 million annually.</td>
<td>The Project Management Organization is integrated into Electric Operations work processes and work hand in hand with the Centralized Regional/Account Organization and our Work Resource Management Organization. This collaboration allows for the alignment and prioritization of work with resources across Electric Operations.</td>
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<td>5 Cost Management</td>
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<td>Increase emphasis on efficiency and effectiveness in operations auditing. (Conclusion 10)</td>
<td>One time cost of $150,000 has been expended to purchase the ACL analytical tool. Approximately $550,000 will be expended annually to maintain the new Auditing section.</td>
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<td>Make consideration of Enterprise Risk Management a more structured part of audit planning. (Conclusion 11)</td>
<td>No incremental cost. Certain benefits, including proactive risk assessment and evaluation and reduction of risk exposure, are expected to be realized.</td>
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<td>40</td>
<td>Establish consistent, company-wide economic value analysis methods and metrics for capital projects and programs. (Conclusions 6 and 7)</td>
<td>The capital cost to-date of implementing the Methodology and prioritization model is approximately $1 million dollars. Annual operating costs are $300,000. We expect to accrue benefits from implementation of a company-wide prioritization methodology based on consistent economic and other quantifiable variables. Savings are expected to exceed the one time and on-going annual costs.</td>
<td>In 2010, CECONY had a capital budget (including smart grid) of $2 billion dollars. By utilizing the methodology, along with other detailed analysis in the Electric T&amp;D areas, we were able to reduce our 2011 Capital budget (including smart grid) request to $1.85B. In preparing for 2012-2016 budget, we will continue to be cost conscious and select the most strategic and cost effective projects/programs.</td>
<td>To date, benefits have been realized in the management of the Common Capital Portfolio; we have strategically reinvested approximately seventeen million dollars in critical infrastructure type projects which otherwise would have been deferred to outer years at a higher cost.</td>
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<td>Implement a holistic approach to cost management that is designed and built around three key elements: (a) a guiding philosophy; (b) a formal, structured cost management plan; and (c) building blocks of comprehensive supporting capabilities (Conclusions 4, 5, 6)</td>
<td>Costs associated with establishing the required groundwork totaled $715,000, and include: extensive team time over the span of one year to coordinate and implement the work plan ($500,000), a third party assessment ($150,000), and the cost to develop new reporting tools ($65,000). Benefits achieved will exceed the $715,000 in implementation costs and result from increased alignment, continued business process improvement, increased communication and awareness, and consistency.</td>
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<td>As skilled people represent the cornerstone of the holistic approach, expand the role of cost management professionals to encompass tasks and accountabilities important to holistic cost management. (Conclusion 5)</td>
<td>Total costs to achieve implementation objectives were approximately $5,000, reflecting nearly 100 hours of direct work. Benefits are expected to exceed the costs to implement this recommendation. The expansion of the roles and responsibilities of cost professionals, more stringent qualification requirements, and support for professional development of Con Edison cost management professionals enables the adoption of an enhanced, holistic cost management program that will support initiatives to formalize the cost management program, balance focus on reporting and root cause analysis, support Line Management, and improve efficiency.</td>
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<td>Establish a cost support organization that is (a) placed consistent with the priority of cost management; (b) serves the cost management needs of all levels of management; (c) develops a force of skilled cost professionals and assures those skills are continuously improved; and (d) has overall accountability for the development and implementation of the cost management program. (Conclusion 5)</td>
<td>No incremental cost. The creation of a centralized Cost Management Director position who reports directly to the President of CECONY has led to a higher priority of cost, increased feedback and oversight. This new alignment ensures consistency of communication across all organizations and independence of cost management personnel. This organizational structure and enhanced role of Cost Management will be integrated with the broader organizational assessment of Con Edison.</td>
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<td>Provide training for managers, supervisors and cost support personnel in cost management techniques consistent with the holistic approach. (Conclusions 2, 5, 6)</td>
<td>The costs in achieving these objectives totaled approximately $8,000. Benefits will exceed costs.</td>
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<td>49</td>
<td>General Recommendation Implementation Guidance.</td>
<td>The cost for implementing this recommendation was approximately $50,000. Expected savings will exceed $50,000 cost of implementation, and will result from better real-time understanding of cost variances and the impact of scope changes and project schedules, and more accurate long-term planning for cash flows, schedules and budgets.</td>
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<td>Sample Cost Management Implementation Tactics.</td>
<td>No incremental cost. The recommended “Cost Management Implementation Tactics” have implemented as part of the Company’s implementation of a holistic approach to cost management. For implementation detail, please see recommendation 45.</td>
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<td>Perform in-depth reconciliation on cost estimates with substantial overrun to better understand the root causes of deviations. (Conclusion 9)</td>
<td>Incorporating the lessons learned and the additional work in the design stages of projects to ensure a more accurate scope of the project requirements, results in an incremental cost of approximately $23,000. This was derived by estimating the cost to hold Lessons Learned meetings; prepare, review, comment and finalize the report and perform additional activities during the design phase of the project. Direct benefits can be achieved through use of the Financial Internet Portal, enhanced variance templates, Estimates vs. Actual report, and Lessons learned from reconciliation of appropriations. Most significantly, better understanding of lessons learned, higher sensitivity to costs, and enhanced long term planning for scheduling and budgets will lead to insightful project reconciliation. For implementation to have a positive impact through these benefits, $23,000 must be saved per project where this process is applied. We expect savings to exceed costs.</td>
<td>During first Quarter 2011, 17 cost comparison analysis were completed. The results indicate that nine (53%) of the projects exceeded the predetermined accuracy margin of +/- 10%. The subject nine projects consist of six overruns and three under runs. Relative to the cost overruns, the primary reasons for cost variances were changes in overhead rates, unanticipated interferences, and change of scope requests by user. Relative to cost under runs, the primary reasons for cost variances were contingency not used, changes in indirect costs, and savings in contractor costs. All completed cost comparison analysis is disseminated throughout Central Engineering and Construction.</td>
<td>The estimating department of Central Engineering established Key Performance Indicators (KPIs) to track the completion of monthly/quarterly cost comparisons analysis between estimates vs. CWEs. The primary objective is to analyze all estimates greater than $2M and or estimates that exceed the predetermined +/- 10% accuracy margin requirement. A root cause determination is established for all variances which then facilitate the establishment of lessons learned criteria to be applied to future estimates. All completed cost comparison analysis are disseminated throughout Central Operations departments including Engineering and Construction.</td>
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<td>Prepare an analysis of corporate overtime expenditures that includes root causes of the upward trends and strategies for attaining more economic levels. (Conclusion 9)</td>
<td>No incremental cost. The key benefits are expected to be improved overtime cost control and increased accountability. Other benefits of this recommendation include the creation of a standard format for overtime reporting, analysis and control, and for high-level historical usage trends correlated to business activity. The Local Guidance Document will afford each organization greater structure in making overtime decisions while maintaining the flexibility to manage its overtime budget. As a result, we expect annual savings of approximately $1 million.</td>
<td>A central site to collect and communicate Lessons Learned is being developed. The Cost Management Team is working with Information Resources to develop a strong search engine for the site so that Lessons Learned can be easily located. The Project Management Society websites will become the central repository for all Lessons Learned across Con Edison. The Lessons Learned process will be standardized. Currently, we have disparate sites with different search mediums, which make it difficult to share Lessons Learned across the entire Company. The centralized site will streamline the process.</td>
<td>We have transitioned to using a central Lessons Learned site which has been established for use by all project managers throughout the Company. This Enterprise &quot;Lessons Learned&quot; repository serves as a one-stop shop for communicating and sharing information. It contains a search engine which allows the user to easily search for information by a key word or phrase. The centralized site helps to streamline and standardize the process of sharing lesson learned.</td>
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<td>Implement a formal program for representatives from each region to share lessons learned in their respective fields. (Conclusions 4, 9)</td>
<td>The cost of the Lessons Learned Program is the development of the SharePoint site and the quarterly meetings of the Lessons Learned Team; the initial cost was approximately $3,120 and ongoing annual costs of $4,000. Benefits will exceed costs.</td>
<td>The estimating department of Central Engineering established Key Performance Indicators (KPIs) to track the completion of monthly/quarterly cost comparisons analysis between estimates vs. CWEs. The primary objective is to analyze all estimates greater than $2M and or estimates that exceed the predetermined +/- 10% accuracy margin requirement. A root cause determination is established for all variances which then facilitate the establishment of lessons learned criteria to be applied to future estimates. All completed cost comparison analysis are disseminated throughout Central Operations departments including Engineering and Construction.</td>
<td>We have transitioned to using a central Lessons Learned site which has been established for use by all project managers throughout the Company. This Enterprise &quot;Lessons Learned&quot; repository serves as a one-stop shop for communicating and sharing information. It contains a search engine which allows the user to easily search for information by a key word or phrase. The centralized site helps to streamline and standardize the process of sharing lesson learned.</td>
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<td>68</td>
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<td>Improve resource planning for design personnel and other essential project personnel. (Conclusion 3)</td>
<td>No incremental cost. Cost savings of approximately 20% ($262,080) annually through increased efficiency and productivity of in-house personnel and reduction of outside the outside services design budget.</td>
<td>Improved resource planning for design personnel and other essential project personnel in Central Engineering have resulted in cost savings of approximately $262,000 annually through increased efficiency and productivity of in-house personnel and reduction of outside the outside services design budget.</td>
<td>The majority of design work has shifted from outside services to in-house designers. We continue to see cost savings of approximately $262,000 annually through increased efficiency and productivity of in-house personnel and reduction of outside the outside services design budget.</td>
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<td>Bring a corporate total holistic approach to cost management to the project and program management efforts. (Conclusion 6)</td>
<td>Incorporating the lessons learned process into all major projects initiated by the Company results in a cost of approximately $21,000 per project. This was derived by estimating the cost to hold lessons learned meetings; prepare, review, comment and finalize the report and perform On-the-Job Training. We expect a positive cost benefit for the Company and our customers. Break-even savings to justify implementation for a sample $15 million project is 0.14% of total project cost.</td>
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<td>70</td>
<td>Strengthen Substation Operations program management processes by adding project management principles in a structured way. (Conclusion 18)</td>
<td>Incremental costs of implementation are estimated at approximately $1.29M annually. These costs include periodic team meetings, increased estimating activity, and the assignment of Program Engineers to all SSO programs. To have a positive cost-benefit impact, the annual cost of continued implementation must be less than its resulting project cost savings. Based on the approximate capital spending levels for Substation Operations (SSO) Programs over the next 3 years, this implies a required break-even savings to justify implementation for the sum total of SSO programs of approximately 1%. Since we expect to achieve savings of at least 1% of the total project cost by utilizing the more formal program management process, we expect a positive cost benefit for the Company and our customers.</td>
<td>As a result of our efforts to establish a more formal approach to program management in Substation Operations we expect to achieve savings of at least 1% on the total SSO Capital Program cost. This would result in annual savings of $1.7 million based on the average expected annual spending levels in 2011 and 2012. Net of annual operating costs, savings are expected to total $400K annually. Implementation of this recommendation also helped us achieve our cost management KPI's related to program and project management. In 2010 we completed 100% of our KPI related projects and programs on schedule and below budget. We also performed 1,606 current working estimate reviews for capital projects and programs versus a goal of 1,000. We are on track to meet these goals in 2011.</td>
<td>Costs and benefits estimates have remained the same since our last update. We expect an annual productivity improvement of 1% on the total SSO Capital Program cost. This would result in annual savings of $1.7 million based on the average expected annual spending levels in 2011 and 2012. Net of annual operating costs, savings are expected to total $400K annually. Implementation of this recommendation also helped us achieve our cost management KPI's related to program and project management. In 2011 we completed 100% of our KPI related projects and programs on budget, and 87.5% on schedule. We also performed 2,695 current working estimate reviews for capital projects and programs versus a goal of 1,500. We remain on track to meet these goals in 2012.</td>
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<td>73</td>
<td>73</td>
<td>Implement a corporate total holistic approach to cost management. (Conclusion 6)</td>
<td>See recommendation 45.</td>
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<td>6</td>
<td>14</td>
<td>Analyze, and redirect as appropriate, the level of effort and sophistication applied to various load forecasting tasks and products, to better balance costs with product and user needs. (Conclusion 2)</td>
<td>No incremental cost. The Company’s forecasting groups eliminated and streamlined tasks, and in so doing, freed up resources for developing sensitivities for the Electric Long Range Plan and supporting more “what if” studies. These new sensitivities should result in a more robust planning process that further considers the impact of economic assumptions, energy policies, and changes in trends and new technologies.</td>
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<td>16</td>
<td>Conduct an R&amp;VF review of certain aspects of its approach to forecasting. (Conclusions 9, 13, 14)</td>
<td>No incremental cost. Studying alternative methods of forecasting could lead to improved accuracy of our forecasts. Since our forecasts are used by other departments, such as Rate Engineering and Energy Management, increased accuracy could lead to improvements in rate design and supply planning processes, and less bill volatility.</td>
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<td>17</td>
<td>Evaluate the factors responsible for consistently under-estimating 5 and 10 year peak load forecasts; assure that any bias is removed from future forecasts. (Conclusion 14)</td>
<td>Minimal cost. Benefit expected to assure a un-biased forecast.</td>
<td>No incremental cost. Benefit expected to assure a un-biased forecast.</td>
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<td>18</td>
<td>Expand load forecasting activities and capabilities to encompass analysis of uncertainties using sensitivity analyses, probabilistic tools or other applicable techniques. (Conclusion 18)</td>
<td>See recommendation 14.</td>
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<td>19</td>
<td>Develop an improved approach to the documentation, testing, and communication of forecast criteria and assumptions. (Conclusion 19)</td>
<td>No incremental cost. The benefit of having the documents is to provide greater awareness of the assumptions and drivers that both forecasting groups use to produce their respective forecasts. It will also ensure consistency when questions are posed about the forecasts since everyone will be able to reference the same information.</td>
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<td>Examine and implement as appropriate the efficiencies and quality improvements that might result from utilization of CECONY’s load research program, modified as cost-effective, to support load forecasting. (Conclusion 26)</td>
<td>No incremental cost. A potential benefit will be the development of more robust electricity demand forecasts, or forecasts for different future scenarios. These forecasts could be used to develop plans for the Company’s electric system for different peak demand conditions.</td>
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<td>23</td>
<td>Establish a structured approach to the consideration of long-term eventualities that might significantly impact load forecasts, such as changes in trends, new technologies and new policies. (Conclusion 30)</td>
<td>No incremental cost. Using demand sensitivities results in a robust planning process and improved capital budgeting. These sensitivities for long-term peak demand forecasts ensure that a range of possibilities for growth in the peak demand are considered and that take into account factors not in existence at the time the forecast is prepared.</td>
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<td>Consolidate duplicative Energy Management operations in the electric and gas hedging functions. (Conclusion 2)</td>
<td>No incremental cost. The results have shown that while some of the activities associated with the hedging functions are similar, a large number of the tasks and knowledge base required to perform electric or gas hedging functions are very different. Accordingly, the staffing level has remained the same. Further, we conclude that any other improvements we achieve as a result of improved coordination between the two groups would not provide Full-Time Equivalent (FTE) benefits, but rather improvements in our analysis or implementation of the hedging plans, the benefits from which automatically accrue to the customers under the existing pass-through mechanisms. Therefore, to the extent that ongoing meetings and subsequent implementation of coordination improvements between the two groups result in hedging benefits or improved performance, those benefits will be directly passed on to customers.</td>
<td>The benefits associated with the merging of the gas and electricity hedging groups include the elimination of a section manager position and the associated reduction in labor costs by approximately $125,000. These savings are reflected in Energy Management’s forward looking budgets.</td>
<td>Savings of approximately $125,000 continue to be reflected in Energy Management’s budget due to the elimination of a section manager position.</td>
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<td>Develop a comprehensive portfolio management plan with quantified goals and objectives to optimize the electric resource portfolio and related hedging plans. (Conclusions 3, 7, 14)</td>
<td>No incremental cost. One benefit of this long-term plan is that we have created a standard format and template for annual review and update. This will provide a means of more robust evaluation of the electricity supply outlook and forecasts, and can be used to develop plans for the Company’s electric system for different future demand and supply conditions. Additional benefits include energy cost savings that could occur if the Company identifies improvements in its energy supply operations. To the extent that there are savings from our strategic purchase decisions, those savings will be directly passed on to customers as they occur.</td>
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<td>Identify, analyze and document all reasonable alternatives to its existing sources for both capacity and energy. Alternatives that are superior to the status quo electric resources should be implemented. (Conclusions 8, 9, 11)</td>
<td>See recommendation 80.</td>
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<td>7 Gas Main Replacement</td>
<td>35</td>
<td>Maintain current information about CECONY’s leak-prone pipe. (Conclusion 6)</td>
<td>No incremental cost. The 50 mile target established could reduce steel leaks by half, and cast iron leaks by two-thirds, over 25 years. The primary benefit of main replacement is the reduction in the risk of serious incidents caused by leaks. Public and employee safety is paramount to the way we manage and operate our gas system.</td>
<td>In addition to tracking our commitment to replace 50 miles of leak prone pipe per year through the 2011-2013 PSC Rate Case Agreement, we have incorporated this into the corporate tracking system (Capital KPI Modifier Program) to ensure compliance. Through the capital main replacement program efforts we expect to reduce the risk of serious incidents caused by leaks.</td>
<td>We continue to track our commitment to replace 50 miles of leak prone pipe per year through the 2011-2013 PSC Rate Case Agreement and as a corporate KPI. The primary benefit of main replacement is the reduction in the risk of serious incidents caused by leaks.</td>
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<td>8 Gas Capacity Planning</td>
<td>15 Find a better way to forecast growth in the peak gas load. (Conclusion 8)</td>
<td>No incremental cost. A primary benefit of this new forecasting methodology will be the independent development of the natural gas peak demand forecast by Demand Forecasting and the energy forecast by the Revenue and Volume Forecasting section of Accounting. This more independent process with its “checks and balances” will help improve the accuracy of the peak demand forecast.</td>
<td>Demand Forecasting reallocated internal resources while also automating and streamlining some of its functions, allowing for implementation of the new demand forecasting methodology without need for additional resources. The primary benefit of this new forecasting methodology will be the independent development of the natural gas peak demand forecast by Demand Forecasting and the energy forecast by the Revenue and Volume Forecasting section of Accounting. This more independent process with its “checks and balances” will help improve the accuracy of the peak demand forecast.</td>
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<td>86 Provide for more regular examination of Gas Supply’s award of supply contracts by Internal Auditing. (Conclusions 7, 8)</td>
<td>No incremental cost. By increasing the amount of review of these procurements in the annual plan, we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place.</td>
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<td>87 Explore applying probability-of-occurrence analysis to its supply-capacity planning. (Conclusion 13)</td>
<td>No incremental cost. As a result of this study for natural gas, the Company gained valuable insight into the natural gas data analysis used in forecasting demand and gas supply risks. We examined our existing assumptions, data definitions, explored new techniques and ideas, which will improve overall processes.</td>
<td>While the Company concluded that the application of probability-of-occurrence analysis to natural gas supply and capacity planning is not currently feasible, it continues to seek to improve its gas demand forecasting and planning capabilities to better plan and manage the cost of natural gas to its customers. The Company gained valuable insight into the natural gas data analysis used in forecasting demand and gas supply risks.</td>
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<td>Implementation costs were minimal as the compensation consulting studies were done as part of the Company’s normal review and assessment of compensation practices. The variable pay component of the current management compensation program places at risk a portion of employee’s compensation which must be re-earned each year through the achievement of pre-determined performance and cost management measures. The reason for having a competitive program is to have the ability to attract outside talent and for retention of competent employees. Performance targets are aligned with payouts to motivate employees to achieve the desired goals. Each year, as part of our annual review process, we review performance indicators to evaluate the effectiveness of the plan and make changes as appropriate.</td>
<td>Efficiency savings of approximately $20,000 per year continue to accrue from the development of the trending feature for the CPI dashboard.</td>
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<td>Increase the amount of stretch and put more pay at risk as part of a broad revamping of incentive compensation. (Conclusions 7, 9, and 10)</td>
<td>No incremental cost. Will align compensation to key goals of the Company.</td>
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<td>Before the study is done and implemented, reduce the emphasis on O&amp;M expense and increase the weighting for capital expenditure performance and the operating performance measures. (Conclusions 7 and 8)</td>
<td>No incremental cost. Will align compensation to key goals of the Company.</td>
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<td>Develop a corporate-wide management information system. (Conclusions 2, 4, 5, 6, 7)</td>
<td>Implementation costs expected to be $180,000. System will provide a proactive approach for monitoring key performance indicators.</td>
<td>The development of the trending feature for the CPI dashboard was completed at a cost of $82,000. Based on a recent survey of the CPI system users, with the previous version of the CPI Dashboard they spent approximately 1,000 hours creating trend and other presentation data. Since these trend charts and associated data tables can now be generated automatically, we anticipate efficiency savings of approximately $20,000 per year, and results in a payback of four years.</td>
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<td>Perform comprehensive resource analysis for all business units on a quarterly or semi-annual basis. (Conclusions 3, 5, 9, 11)</td>
<td>The cost to implement this recommendation was $400,000. The $400,000 was composed of $240,000 for the software over the three year subscription period, a one-time $155,000 for system implementation, and $5,000 related to the evaluation of this recommendation by subject matter experts. Beyond the third year, the annual software subscription is $80,000. For the next three years, we expect savings of $163,000 per year (i.e., $515,000 due to the optimization of skills training and $113,000 due to automated report generation). The total savings over the next three years is $489,000. Beyond the third year, we expect continued net savings above the annual costs.</td>
<td>In 2012, due to reduced need for splicer training based on projecting splicer attrition using VEMO, we expect to reduce the number of Splicer Instructors by two. The average cost of a splicer instructor is $115K. The cost of two instructors is $230K and the annual cost for VEMO in 2012 is approximately $110K. This would be a one year savings of $120K.</td>
<td>We continue to utilize the VEMO application for workforce planning and have achieved annual savings of approximately $120,000 due to the reduction of 2 splicer instructors.</td>
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<td>Assess and monitor the productivity and cost impacts of carrying an extra trainee on some work crews on a continuous basis to achieve more efficient resource management. (Conclusion 5)</td>
<td>No incremental cost. Knowing the cost and productivity impact of carrying the extra trainee will provide a better understanding of cost variations and the impact on productivity, which will help in making financial decisions in hiring practices. To ensure consistency throughout Electric Operations, and to assess and monitor these impacts going forward, a guideline document to clarify on-the-job work accounting practices has been established for reference.</td>
<td>Gas Operations has seen steady improvement in its safety performance. The OSHA incident rate through August 2012 was 2.15 with 18 total injuries or illnesses. Through the same period in 2011, it was 3.36 with 23 total injuries or illnesses.</td>
<td>Gas Operations has seen steady improvement in its safety performance. The OSHA incident rate through August 2011 was 2.64 with 18 total injuries or illnesses. Through the same period in 2010, it was 3.36 with 23 total injuries or illnesses.</td>
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<td>Conduct a root cause analysis of the upward trend in OSHA target rate in Gas Operations and prepare and implement a corrective action program. (Conclusion 7)</td>
<td>No incremental cost. This improved focus should result in a continued reduction in injuries while improving productivity and potentially reducing costs associated with injuries. Achieving this level of performance by 2014 represents an improvement of greater than 50% over Gas Operations’ performance during the previous 5 years. Cost savings are the result of the more important reduction in the occurrence and duration of employee injuries. The ultimate goal of our strong and continued focus on safety is an injury free Gas Operations workforce.</td>
<td>Gas Operations has seen steady improvement in its safety performance. The OSHA incident rate through August 2012 was 2.15 with 18 total injuries or illnesses. Through the same period in 2011, it was 3.36 with 23 total injuries or illnesses.</td>
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<td>Increase efforts to segregate safety from contractual issues in management / bargaining unit dialog. (Conclusion 6)</td>
<td>This initiative will be implemented in phases, starting in 2010 with Local 3. The incremental costs have been estimated at approximately $25,000 for 2010. Phase 2 would begin in 2011 after a review of the results of Phase 1. The Company expects that by implementing the Health &amp; Safety Ladder system, union / management relationships should improve and there would be some related savings due to the reduction in grievances and arbitrations. We expect savings to exceed costs. See additional benefits related to an improved focus on safety in recommendation 5B.</td>
<td>The costs and benefits have not changed, except that they have moved one year forward. While we expected the costs to materialize in 2010, the bulk of the work did not occur until 2011, and will continue in 2012 for this pilot program. The Company expects that by implementing the Health &amp; Safety Ladder system, union / management relationships should improve and there would be some related savings due to the reduction in grievances and arbitrations. See additional benefits related to an improved focus on safety in recommendation 5B.</td>
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<td>Review safety targets with the objective of adapting “stretch,” but attainable, levels that exceed historical averages. (Conclusion 6)</td>
<td>No incremental cost. Safety is a top priority for the Company. The primary driver for improved safety performance is to ensure that our employees work safely and “go home the way they came to work.” It also fosters a company culture that sustains our commitment to safety and health, contributes to injury reduction, and improves worker morale. In addition, financial benefits will be achieved. Achieving the new safety goal would improve productivity and reduce costs associated with injuries.</td>
<td>The company met and exceeded the 2010 goal for the OSHA incident rate (2.48/2.91 goal). A OSHA incident rate goal was established for 2011 for CECONY which will continue to lead us towards the 2014 goal of 1.5. Currently, we are at 1.95 (through August) which places the Company in the right direction to meet the year end goal for CECONY of 2.56.</td>
<td>The Company met and exceeded the 2011 goal for the OSHA incident rate (1.92/2.56 goal). A OSHA incident rate goal was established for 2012 for CECONY which will continue to lead us towards the 2014 goal of 1.5. Currently, we are at 2.27 (through July) which places the Company in the right direction to meet the year end goal for CECONY of 2.21.</td>
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<td>Strengthen enforcement of contractor compliance with their safety programs. (Conclusion 8)</td>
<td>No incremental cost. Reinforcing our contractor’s commitment to safety there is the potential for reduced contract-worker injury.</td>
<td>Approximately $10,000 in Company labor was spent in developing and implementing recommendations to strengthen enforcement of contractor compliance with their safety programs. The cost associated with revising the Contractor eHASP training module and developing the COS training module was approximately $38,000. The benefits achieved through these training courses and the implementation plan are enhanced control over contractors and their work site conditions, enhanced contractor evaluations, better written contractors’ eHASPs and increased contractors’ awareness on their eHASPs. By reinforcing our contractor’s commitment to safety there is the potential for reduced contract-worker injury. The OSHA Recordable injury incidence rate for contractors has been reduced from 2.58 in 2009 to 1.84 in 2010 and 1.84 for YTD 2011.</td>
<td>The Contractor OSHA Rate for 2011 was 2.12 compared to a goal of 2.56. The 2012 Contractor OSHA Rate through June is 1.3 compared to the year end goal of 2.21.</td>
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<td>Establish a corporate philosophy, policies and supporting guidelines for the balancing of in-house and contractor resources. (Conclusion 12)</td>
<td>The standardized review will be conducted at minimal cost and is already performed as part of existing practices. We anticipate cost savings from the use of the standardized guideline to obtain the optimal mix of in-house and contractor resources on various work activities. In the aggregate of all specific projects, staff augmentation, and outsourcing activities that the Company utilizes, we believe that we will see savings from this disciplined approach.</td>
<td>The HR Guidance Memo reinforced and standardized our practice that a cost/benefit analysis is performed when required to obtain the optimal mix of in-house and contractor resources. On recent example is the outsourcing of the garnishments process in Payroll. After performing a cost benefit analysis, this outsourcing solution estimates annual savings of $68,000.</td>
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<td>61</td>
<td>Establish a corporate philosophy, policies and supporting guidelines to provide managers and supervisors with a framework to manage overtime. (Conclusion 9)</td>
<td>The cost of the benchmarking study was approximately $4,000. The key benefits are expected to be improved overtime cost control and increased accountability. Other benefits include the creation of a standard format for overtime reporting, analysis and control, and for high-level historical usage trends correlated to business activity. The Local Guidance Document will afford each organization greater structure in making overtime decisions while maintaining the flexibility to manage its overtime budget. a combined with efforts of recommendation 62, we expect annual savings of approximately $1 million.</td>
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<td>Advance the continuous improvement efforts under The Way We Work program. (Conclusions 1, 2)</td>
<td>The cost to develop the training programs was approximately $142,000. Benefits are expected to exceed costs through the training programs. These courses include basic training to employees on important analytical, cost and project management principles that are critical for managing the Company’s programs and projects. In addition, these courses will promote and develop better teamwork and group communication, and enhance customer service through improved processes and innovation. The project management course provides an understanding of detailed work-breakdown structures that support more accurate scheduling and cost estimates.</td>
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<td>Include pertinent productivity improvement goals in future KPIs at various management levels. (Conclusion 3)</td>
<td>No incremental cost. The utilization of KPIs is expected to help facilitate achieving the productivity improvements described in the Electric, Gas and Steam rate settlements.</td>
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<td>Participate more actively in external information sharing efforts. (Conclusion 10)</td>
<td>No incremental cost. Benefits are expected through the enhancement and organization of information sharing and benchmarking efforts at Con Edison to support better processes, tools and technologies and to improve decision-making.</td>
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<td>Revise the performance measures (KPIs) for energy management to provide metrics and incentives that align with electric procurement objectives. (Conclusion 4)</td>
<td>No incremental cost. Potential benefit is better alignment between procurement and the stated objectives.</td>
<td>No additional resources were required. The new KPI to complete and review the Company’s Long Term Electricity Supply plan increases the line-of-sight between short- and long-term planning and the resulting impact on system constraints and customer costs. These KPI modifications also increase accounting accuracy and transparency.</td>
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<td>Implement reliability programs to determine if they should be terminated earlier to release capital expenditures for more cost effective reliability programs. (Conclusion 3)</td>
<td>Minimal implementation cost. The development of cost-benefit profiles for distribution programs have allowed for the contraction of eight programs resulting in a cost avoidance of about $40 million. Programs for critical transmission assets (transformer and breakers programs) have allowed us to realize a cost avoidance of $24 million in savings in 2009.</td>
<td>In 2010, program tiering resulting from a cost-benefit analysis of the targeted PILC replacement program resulted in an additional ongoing annual reduction of $10 million. Additionally, the termination of the Coastal Storm Mitigation program resulted in a $1 million savings. Finally, in 2011, the completion of 4 additional non-network cost-benefit analyses, although not resulting in a reduction in capital expenditures, provided for a 5% improvement in non-network SAIFI at no additional cost. Improvements in system risk resulting from the impact of capital budgets are substantiated through the overall reduction in operational problems during peak load periods. Asset optimization strategies for transmission assets continue to provide benefits through reduced capital expenditures. Analysis was performed to determine various transmission components’ contribution to load shedding events. Three components were identified as low contributors and these programs were re-evaluated for the current five-year capital budget plan. Funding over the five-year capital plan was reduced for the 138kV Breaker Program, 345kV Breaker Program and Disconnected Switched Program, by $13 million, $9.2 million, and $4.4 million respectively. In addition two programs, the Capacitor Cable Upgrade Program with annual funding of $3 million and the Substation Loss Contingency Program with annual funding of $2 million, were shown to have limited strategic value and were removed from the current five-year capital budget plan.</td>
<td>Through the development of cost-benefit profiles for distribution programs, we have reduced our capital budget for electric distribution programs by $51M from our 2009 pre recommendation levels and these referenced Capital budgets currently remain at or slightly below their post adjustment level. We continue to realize an annual reduction in Capital Reliability spend of $10M due to a contraction of the PILC program. Programs for critical transmission assets were analyzed for their reliability impact and cost-effectiveness, this allowed us to realize $24M in savings in 2009. Going forward funding over the five-year capital plan has been reduced for the 138kV Breaker Program, 345kV Breaker Program and Disconnected Switched Program, by $13 million, $9.2 million, and $4.4 million respectively. Two programs, the Capacitor Cable Upgrade Program with annual funding of $3 million and the Substation Loss Contingency Program with annual funding of $2 million, were shown to have limited strategic value and are no longer funded in our capital budget plan.</td>
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<td>Asset Optimization</td>
<td>Analyze networks and the 138kV system designed to N-1 standards to determine the extent that maintenance activities can be performed at load levels less than peak load; where appropriate, incorporate maintenance design requirements into relevant design standards (Conclusion 6)</td>
<td>No incremental cost. Studies were able confirm the adequacy of existing maintenance procedures during non peak periods to ensure no impact to customers. The Company will continue to annually evaluate if additional emergency tie feeders or switch upgrades are warranted and are cost justified.</td>
<td>As related to the 138kV System – N-1 Design, substations previously identified as having restricted maintenance periods have already benefited or will benefit from load relief or load transfers to provide greater flexibility in scheduling equipment outages during the entire non-summer period. As related to Auto-loops, based on the past performance of the 18 auto-loops that have manual emergency tie switches and established Company procedures regulating maintenance work, the capital expense to install SCADA-controlled or automatic switches on these 18 auto-loops is not cost justified.</td>
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<td>Clarify transmission planning criteria with regard to transfers used during second contingency analysis. (Conclusion 8)</td>
<td>No incremental cost. Improves operational clarity to stakeholders and maintains compliance with regulatory reliability performance criteria.</td>
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<td>Perform a global review of all equipment ratings, input data, and time durations across the distribution and transmission areas to assure consistency and to justify and document differences. (Conclusion 24)</td>
<td>No incremental cost. Provides more representative temperatures for the underground environment, which will produce more realistic equipment ratings. The benefit is that equipment is neither underrated, resulting in unnecessary load relief work, nor overrated, resulting in possible equipment overloads during high load periods.</td>
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<td>Maintain the 2011 completion date for completion of network secondary topology updates and EPRI DEW software. (Conclusion 16)</td>
<td>No incremental cost. Potential reduction in capital expenditures on primary feeder and transformer reinforcement due to a more accurate load representation on specific assets. Model will support automated load distribution in place of the manual process currently used.</td>
<td>A comparative analysis of the former modeling method of concentrating demand at the transformer and the new distributed demand process demonstrated that refined distributed demand model resulted in fewer overloaded primary section and transformers. The analysis of the two modeling methods was completed on four Bronx networks and judged against a common load background. The approximate cost of developing these four distributed demand models was $450K; the reduction in overloads resulted in $1.8 million dollar savings in system reinforcement spending. DEW software failed to give correct and consistent results, and continued implementation would require extensive work in order to satisfy the Company’s distribution modeling needs. Alternative software products from Siemens and CYME were implemented after evaluation found them to be cost effective to complement the Company’s existing modeling process.</td>
<td>We continue to evaluate the cost benefit of new 3G designs, and will update existing cost benefit analyses of major substation projects when the service dates are closer. Long term cost benefits of new 3G opportunities are now being evaluated and quantified for inclusion in the Integrated Long Range Plan. The 3G cost avoidances and savings were built into the Electric Long Range Plan and are forecasted to be $650 million over the 20 year planning horizon.</td>
<td>The Company has incorporated DSM into the existing Load Forecasting and Load Relief planning processes, the Electric Long Range Plan and has worked with NYSERDA to target 3G incentives in networks with future load relief needs. DSM provides the potential to defer infrastructure investment.</td>
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<td>Perform a least cost system analysis that minimizes costs to customers with regard to implementation of 3G strategies. (Conclusion 17)</td>
<td>Costs are associated with Electric Long Range Plan development, see recommendation 5. These 3G designs provide not only less asset intensive designs, but also the capability to optimize the utilization of assets we currently own, allowing us to defer some of the large capital expenditures that would be required by implementing a traditional design. This is another example of how the Company strives to meet the needs of the customers in a more cost-effective way. The 3G cost avoidances and savings are built into the Electric Long Range Plan and are forecasted to be $659 million over the 20 year planning horizon.</td>
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<td>Perform analyses to determine if peak demand can be reduced more economically than the addition of infrastructure. (Conclusion 19)</td>
<td>Proposed DR program cost is $22 million to be collected as a surcharge. Studies proposed in 12/08 filing to cost approximately $200K; program cost to be estimated after studies are completed. Studies for incremental voltage reduction to cost approximately $200K; program cost to be estimated after studies are completed. Potential for peak demand reduction programs to be cost effective compared to infrastructure investment.</td>
<td>There is a positive cost benefit for the installation of distribution capacitors, and the Company has begun installing them under the 4kV Grid Modernization program. There is potential to defer infrastructure through Demand Side Management (DSM), and the Company has incorporated DSM into the existing Load Forecasting and Load Relief planning processes, and the Electric Long Range Plan. Since only a small benefit exits for phase balancing, it will only be applied in specific areas where it is economically feasible. Voltage reduction is not utilized as a planning tool to reduce capital infrastructure, however it is utilized for operational purposes.</td>
<td>The company plans to continue to outfit all the switches installed with SCADA during the fall of this year and during the spring of 2012. The strategic deployment of SCADA equipped sectionalizing switches results in the reduction in feeder loading experienced during a contingency. This will result in less reinforcement work to replace feeder components and, therefore, capital savings. Because SCADA operation avoids increased loading on alternate components, critical components do not require reinforcement in order to remain in service.</td>
<td>The Company has incorporated DSM into the existing Load Forecasting and Load Relief planning processes, the Electric Long Range Plan and has worked with NYSERDA to target 3G incentives in networks with future load relief needs. DSM provides the potential to defer infrastructure investment.</td>
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<td>Actively pursue the economic use of SCADA controlled network mid-point feeder sectionalizing switches or circuit breakers to reduce system investment. (Conclusion 20)</td>
<td>No incremental cost. Specific cost savings will be dependent on load growth in a particular network, the loading levels of existing components, and the planned reinforcement activity. More cost-effective risk mitigation initiatives could also be achieved and associated installation costs avoided with SCADA equipped sectionalizing switches.</td>
<td>The company plans to continue to outfit all the switches installed with SCADA during the fall of this year and during the spring of 2012. The strategic deployment of SCADA equipped sectionalizing switches results in the reduction in feeder loading experienced during a contingency. This will result in less reinforcement work to replace feeder components and, therefore, capital savings. Because SCADA operation avoids increased loading on alternate components, critical components do not require reinforcement in order to remain in service.</td>
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<td>Evaluate potential changes in the business environment for each of the businesses; for the Gas Business Unit, Strategic Planning should advise Gas Engineering regarding potential demands on the gas transmission and distribution systems occasioned by those changes. (Conclusion 16)</td>
<td>Implementation of a long range plan cost approximately $1.0 million. The duration of the plan we expect to realize a total of about $147 million in operations and maintenance savings and cost avoidance. We expect that our planned level of capital investments will result in average savings or cost avoidance of $7.0 million per year.</td>
<td>From 2010 to 2030, Con Edison expects to realize a total of approximately $46 million in operations and maintenance savings or approximately 2.5% of gas transmission and distribution operation and maintenance costs. We expect to save $428 million in capital expenditures over the 20 year horizon (excluding incremental new business growth) from our current budget levels.</td>
<td>As a result of our integrated long range planning efforts, our 20-year gas capital expenditure forecast has increased by approximately $600 million since the 2010 Plan. This increase is largely due to our recent expectation of additional oil conversions and public improvement investments. Through our planning efforts we have identified an additional $50 million in savings over the 20-year horizon to help offset cost increases.</td>
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<td>Report to stakeholders and the NYPSC on any expansion of the transmission and distribution systems required to serve winter-period electric power generation. (Conclusion 18)</td>
<td>No incremental cost. A cost-benefit analysis based on reinforcing the transmission system for electric generation revealed that no savings to Con Edison would be realized. Con Edison is not responsible for the capital cost associated with reinforcement associated with interruptible customers. As in past gas transmission reinforcement projects, generators contributed to the cost of the projects in order to receive additional, interruptible gas supply. The remaining costs of the projects were funded by Con Edison in order to provide additional gas to firm gas customers and to improve reliability.</td>
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<td>Identify a Steam Master Plan and incorporate within it a greater emphasis on what is happening on and to its distribution system. (Conclusion 4)</td>
<td>Cost of Steam Long Range Plan was approximately $500,000. The Plan Case is estimated to yield annual savings of $20 million from operating expense reductions and $22 million savings from fuel switching in gas addition projects based on the various assumptions used.</td>
<td>Our Steam Long Plan is under revision including updated cost savings and avoidances over the 20-year planning horizon. We expect to realize approximately $40 million in tax savings, $770 million in O&amp;M savings and have identified the potential for over $1 billion in fuel savings over the course of the plan. The estimated fuel savings will depend on fuel price differential over the 20-year planning horizon and our revised plan will discuss in detail expected cost savings and avoidances.</td>
<td>The Integrated Long Range Plan includes estimated steam operating expense savings of approximately $1.8 billion over the 20 year planning horizon. O&amp;M savings are the result of the shutdown of the Hudson Avenue Boilers, management of the Ravenswood A-House and fuel savings from the Hudson Avenue boiler retirement, revised Steam Production Plant Operating Criteria, the minimum oil burn settlement at the Federal Energy Regulatory Commission and natural gas addition projects at the 59th Street and 74th Street Generating Stations.</td>
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<td>Staff a project coordination/specialist group under the Chief Distribution Engineer to assist in the execution of distribution capital projects such as the main replacement program. (Conclusion 1)</td>
<td>The cost for implementing the program (software, training, and certification) is $25,000. The biggest benefit is expected to be improved cost control and program schedule accountability. This could potentially equate to an efficiency improvement of $700,000 on the total spending level for the replacement of leak-prone pipe if we achieve a 3% productivity improvement.</td>
<td>A 2011 end of year unit cost target of $406 per foot of main replacement was established for the gas main replacement program. Meeting this target will result in a 3.3% reduction from the actual 2010 unit cost of $420 per foot of main replacement, resulting in a total annual cost reduction of approximately $2.7 million. These cost targets are monitored and reported for each operating area and we are currently on target.</td>
<td>In 2011 we met our unit cost target of $406 per foot for our main replacement program. Meeting this target resulted in approximately $2.7 million in savings over the 2010 unit cost. Savings going forward will be dependent on the amount of projects governed by the project management group.</td>
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<td>Improve and expand the current project scope documentation to add sections on risks and rewards and alternative methods. (Conclusion 2)</td>
<td>No incremental cost. Result in an improved decision making process.</td>
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<td>Start benchmarking with other urban utilities and utilize what these other utilities are doing better to improve the CECONY program and project management of capital projects. (Conclusion 3)</td>
<td>The cost of performing the benchmarking study was minimal. Implementation benefits may include all costs avoided as a result of doing Conceptual Packages prior to budgeting and detailed design. Conceptual Packages done up front should result in fewer design and construction changes, thereby providing a cost avoidance due to project changes in the detailed engineering phase of the project or in construction.</td>
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<td>Identify projects requiring the application of project management techniques through a more formal, structured process. (Conclusion 1)</td>
<td>No incremental cost. The benefit is the development of a more formal, structured process for project management in Steam Operations. Savings are expected from overall improved planning, scheduling and cost control for the major projects where these techniques would apply. For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that there will be 1% savings for efficiency improvements associated with project management techniques.</td>
<td>For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that there will be 1% savings for efficiency improvements associated with project management techniques.</td>
<td>We have applied a formal project management application to a total of nine projects in Steam Distribution. The use of a more formal and structured process for project management helped Steam Operations come within 1% of its original forecast for total 2011 Steam Distribution capital expenditures. Going forward we estimate that we will continue to see a 1% savings for efficiency improvements associated with project management techniques.</td>
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<td>Train steam distribution operations personnel in work and project management techniques. (Conclusion 3)</td>
<td>The cost associated with training of employees was $3,500. The benefit is the expansion of formal project management training for those individuals in Steam Operations responsible for project management. For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that there will be 1% savings ($30,000) for efficiency improvements associated with project management techniques.</td>
<td>For Steam Distribution, an estimated three projects per year, totaling $3M, would be suitable for formal project management application. We estimate that there will be 1% savings ($30,000) for efficiency improvements associated with project management techniques.</td>
<td>The benefits of this formal project management training, in addition to the formalized procedure for project management have led to efficiency improvements on various projects in Steam Distribution. Savings accounted for under recommendation 77.</td>
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<td>Internal Auditing should schedule more frequent audits of electric procurement decisions, documentation for entering into electric supply contracts, and daily purchase decisions. (Conclusion 27)</td>
<td>No incremental cost. In 2008 we spent $3.5 billion for the procurement of electric energy. By increasing the amount of review of these procurements in the annual plan we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place.</td>
<td>By increasing the amount of review of these procurements in the annual plan we increase the ability to ensure that the expenditures and the procurement decisions are made in compliance with all controls that have been put in place. Auditing has not incurred any additional cost to address these audits.</td>
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<td>Document processes, procedures, and guidelines for electric supply and scheduling, and for the 20 percent purchase flexibility in electric hedging. (Conclusion 20)</td>
<td>No incremental cost. Qualitative benefits include increased knowledge transfer, consistency in process, and flexibility and control of the hedging process.</td>
<td>No additional costs or benefits have been incurred or realized. The Physical Electricity Scheduling Manual is being used as a reference to support evaluation of scope and required functionality of required electricity scheduling software.</td>
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<td>Make finding means for increasing interdepartmental coordination an Energy Management priority. (Conclusion 3)</td>
<td>No incremental cost. Changes show alignment within Energy Management that reflects industry best practices and do not result in higher costs. To the extent that the results of the ongoing meetings and subsequent implementation of coordination improvements between the two groups results in hedging benefits or improvements, those reduced costs will be directly passed on to customers as they occur.</td>
<td>The benefits associated with the merging of the gas and electricity hedging groups include the elimination of a section manager position and the associated reduction in labor costs by approximately $125,000. These savings are reflected in Energy Management’s forward looking budgets.</td>
<td>See Recommendation 79 for savings.</td>
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<td>Expand Gas Supply’s range of potential capacity alternatives as it considers firm customers’ peak-day requirements for supply. (Conclusions 14, 15)</td>
<td>No incremental cost. Offers for peaking supplies are evaluated and the least-cost supplies are selected based on established guidelines. Any cost benefits realized through these peaking supply arrangements would be passed along to the firm gas customers through the Monthly Gas Cost Factor.</td>
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<td>Conduct occasional Gas Supply tests to identify potential additional types of supply arrangements. (Conclusion 18)</td>
<td>No incremental cost. These new supply points expand the range of suppliers that can participate in the Company’s natural gas procurement activities. Any reductions in cost associated with new supply arrangements will be passed on to customers through the gas adjustment clause.</td>
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<td>Keep financial and credit information for gas suppliers current. (Conclusion 21)</td>
<td>No incremental cost. Reduced risk of entering into transactions with counterparties whose credit rating is unacceptable to the Company.</td>
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<td>Find specific, objective ways for Gas Supply to evaluate its own performance. (Conclusion 28)</td>
<td>No incremental cost. Improvements resulting from self assessment activities have the potential to lower gas cost, extract additional value from the Company’s supply contracts, and improve the accuracy of the work. While we expect savings to result, it is difficult to estimate the magnitude. To the extent savings are realized, they will be passed on to customers.</td>
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<td>In 2011, the Company executed a total of five AMAs, and as a result, gas supply costs in customer bills will be reduced by an estimated $9.1 million. The revenue received from the AMAs will reduce gas costs for customers as those benefits flow through the gas adjustment clause.</td>
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<td>Solicit proposals for external asset management. (Conclusions 29, 31)</td>
<td>No incremental cost. In 2009 and 2010, the company executed a total of six Asset Management Agreements, and as a result, gas supply costs in customer bills will be reduced by an estimated $2.3 million over the two years.</td>
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<td>In 2012, the Company executed a total of five AMAs, and as a result, gas supply costs in customer bills will be reduced by an estimated $9.7 million. The revenue received from the AMAs will reduce gas costs for customers as those benefits flow through the gas adjustment clause.</td>
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